SMALL HYDRO '86

PROCEEDINGS

Ontario Ministry of Energy
Honourable Vincent G. Kerrio Minister
Energy Ontario

SMALL HYDRO '86

PROCEEDINGS

SKYLINE HOTEL, TORONTO

MARCH 5-6, 1986

Copyright, Ontario Ministry of Energy 1986
ISBN 0-7729-1542-3
Price $10.00

1) Small Hydro Markets

. THE INTERNATIONAL SMALL HYDRO MARKET
Fabian Acker 3

. SMALL HYDRO: CANADIAN MARKET TECHNICAL POTENTIAL AND THE MARKET
Charles Figueiredo 17

2) Municipal Experience

. THE FANSHAWE DAM PROJECT
Doug Leitch 39

. THE TRENTON DAM NO. 1 PROJECT
Neil Robertson 49

. THE WEMINDJI SMALL HYDRO PROJECT
Walter Hughboy and John Lemieux 55

3) Private Experience

. THE BURK'S FALLS SMALL HYDRO PROJECT
Bryon Bates 71

. FRONTIER LODGE SMALL HYDRO PROJECT
Pam Townsend 79

. PRIVATE DEVELOPMENT OF HYDRO POWER IN BRITSH COLUMBIA: MOSES INLET EXAMPLE
Glen McDonnell 89

4) Economics of Small Hydro

. SMALL HYDRO ECONOMICS IN ONTARIO: THE PROJECT PERSPECTIVE
Terry Burrell 105

. PRIVATE POWER PRODUCTION IN ONTARIO: ONTARIO HYDRO'S PERSPECTIVE
Amir Shalaby 123

SMALL HYDRO MARKETS

5) Keynote Address

. KEYNOTE SPEAKER
Hon. Vincent G. Kerrio 151

6) Ontario Programs

. ONTARIO'S SMALL HYDRO ENCOURAGEMENT PROGRAM
Ian Lewis 161

. SMALL HYDRO APPROVALS PROCESS
John Morton 177

7) Other Canadian Jurisdictions

. AN OVERVIEW OF EMR POLICIES AND ACTIVITIES
Jay Barclay 193

. SMALL HYDRO DEVELOPMENT ON ONTARIO'S HERITAGE CANALS
Jim Christakos 215

. THE STATUS OF SMALL HYDRO IN QUEBEC
Paul Lavoie 235

8) U.S. Small Hydro Experience

. U.S. POLICIES ENCOURAGING SMALL HYDROELECTRIC DEVELOPMENT: AN OVERVIEW
Ross Ain 243

. PATTERNS OF HYDRO DEVELOPMENT IN THE UNITED STATES
Carol Cunningham 249

9) Financing Small Hydro Projects

. SELECTED CONSIDERATIONS IN FINANCING SMALL HYDRO PROJECTS
Gordon Graham 265

. FINANCING SMALL HYDRO DEVELOPMENTS
John Lackey 275

THE INTERNATIONAL SMALL HYDRO MARKET

Fabian Acker
International Waterpower and Dam Construction

The need to develop small hydro resources is becoming more urgent; in the Third World because of the rising populations, and in the developed world because of the growing awareness of environmental restraints. In addition, both developing and developed countries are affected by the finite limitations of conventional thermal sources and no matter how cheap oil may be now, it must become more expensive as this resource is depleted. One could argue that a reasonable response to these pressures is the development of large-scale hydropower (where appropriate) which would avoid some of the problems associated with thermal or nuclear plant. This is not always the best answer.

Large-scale hydro needs potentially large load centres; as the load becomes more diffuse geographically, the cost of distribution becomes uneconomically high. The 2000 MW Cahora Bassa scheme in Mozambique is a good example. Without the assured load of South Africa 1400 km away, the project would not have been worth building. It could be argued that for the development of Mozambique, a hundred small projects, scattered around the country, would have been more suitable.

The project also highlights the problem of estimating the total small hydro potential in the developing countries. Their exploitable hydropower can be tabulated with the usual degree of uncertainty. The problem is deciding what portion of this is suitable for the development of small schemes. The People's Republic of China, for instance, has an exploitable potential of 380,000 MW; the small hydro portion is estimated at 70,000 MW - that is about 18 per cent of the total. However, the Chinese take "small" as being anything below 12 MW unit capacity, whereas I think there is a case for lowering this limit.

Other countries in Asia are developing their small hydro too (Table 1), although not to the extent of China. It would be tempting but misleading to extrapolate from China or from any

other developing country because the principle factors which influence the split between large and small (whether the break is at 10 MW, 6 MW or 2 MW) are population density, climate, geology and so on.

Another factor affecting the proportion of small to large hydro is the existing level of hydropower exploitation. As a whole, the world has developed about 10 per cent of the total capacity possible, that is about 277 GW out of a possible 2857 GW. The developed capacity varies widely - 56 per cent in Western Europe, 1.3 per cent in Africa (report PU/CES 70, The Center for Environmental Studies, Princeton University, New Jersey, USA). Table 2 gives an indication of the state of development in Europe.

The countries with a strong hydropower development such as the USA will exploit more of the remaining potential with small plants (the best sites having already been developed) than one with a low level of hydropower development such as South America. So, to take these two examples, North America will exploit for small development a higher percentage of what is left and South America less. But in absolute terms they may each develop a similar percentage of the total, that is, of the developed and available potential. This therefore makes the following assumption relevant to all countries with hydropower: that somewhere between 5 and 15 per cent of all of their hydropower, exploited and exploitable, will be developed for small stations.

Based on Princeton's figures, the total world hydropower is 2857 GW potentially plus 277 GW installed, that is 3134 GW; based on my estimate, anything between 157 GW and 470 GW (157,000 to 470,000 MW) will be developed as small hydro.

Just how many machines will be built to meet this capacity brings us back to the question of what is meant by "small". A useful way of deciding whether a machine is "big" or "small" is to consider whether it is mass produced.

Turbines which can be made in standard runs - mass produced might be too specious a concept - range from a few kilowatts up to 2 MW. Above that level, machines are designed for particular applications and, although they may only vary slightly from one to another they are, nevertheless, individually designed. Below 2 MW, the cost of individual design is excessive. Manufacturers tend to produce a standard range of machines up to 2 MW from which the client can make the best choice. Therefore, I define a small hydro machine as anything up to and including 2 MW and there is a market now for about 78,500 to 235,500 small turbines.

THIRD WORLD NEEDS

The predictions of Malthus, that populations tend to grow faster than the means to sustain them, has so far been cruelly illustrated in the Third World. However, it is not universally true, nor is it true for all time, and successful marketing in the Third World will be based on understanding this condition.

Energy and irrigation play key roles in this problem and a great deal of money has been invested in developing these sectors, some of it wasted. Most Third World requirements are for food, shelter, warmth and relief from drudgery. Many of these can be supplied by small-scale hydropower. Consider a small village in the Punjab or Nepal. The overwhelming objective of the villagers is precisely the same as ours - that is to stay alive. They need to grow food, to cook it and to store it. A lot of crops are gathered and dried in the sun for storage. Pests and rodents take about a third, and unseasonal weather may spoil another third. A source of heat to supplement the sun could perhaps double the quantity of food stored with no extra effort and no more land placed under cultivation. Which manufacturers, then, are making hot air blowers driven directly by hydropower?

Cooking is a major consumer of energy in Third World communities, and even putting aside for a moment the disastrous destruction of the world's forests, the process of finding and bringing wood for cooking is taking more and more time leaving less time for growing and harvesting. Because of the increasing scarcity of wood, food is often not adequately cooked. Rice-eating communities, for example, who are short of wood will husk the rice excessively to reduce the cooking time and hence the energy consumed. However, this diminishes its nutritive value. Therefore, running to keep still, the consumers must eat more rice, and therefore grow more rice, and therefore clear more forest and thus reduce still further their wood supply.

The simple way out of this destructive cycle is to use another source of heat for cooking. Which manufacturers have considered the development of cooking stoves, based on off-peak electricity? As we shall see later, off-peak loads are important for the economy of a rural system.

What about milling and husking? In medieval England, millers used to take up to a quarter of the grain they milled as payment. The same often happens in Nepal and India. Which manufacturers have developed simple mills or rice-huskers driven by hydropower that are small enough to be used at village level?

The answer to these questions is "few, if any". Yet all of these devices - heaters, rice-huskers and off-peak cooking stoves - have been developed and are waiting for some

entrepreneurs to take them further and market them. Lending and financial agencies are becoming more sympathetic to small-scale development such as small hydropower, yet time and again the money, goodwill and effort invested does not yield results and the agency, the contractor or the project falls into disrepute and no further schemes are put forward for development.

Many water-to-wire packages are now available, but what happens to the electricity after it gets out of the wire? Commonly it is used to light homes or temples, reducing consumption of oil and paraffin and generally making life a little more pleasant - for perhaps six hours in twenty-four. But to supply a community with a small hydro plant for the purposes of lighting only is an enormous waste of resources and may, in the end, be counter-productive. Recalling that food is fundamental to a community's survival, how will adequate lighting help to provide it? What is needed in the first instance is useful loads such as freezers, blowers, cooking stoves, heat for drying, processing and curing. After these loads are established, electric lighting can be considered. Often it does not have to be "after" but "in conjunction with". If the loads can be spread carefully throughout the day, then lighting could be an integral part of the system and not an isolated convenience.

Irrigation can also be provided by small hydropower systems. Obviously, dams will provide storage, and large dams will provide more storage. This may be useful for a highly organized agricultural system, but may not easily serve small communities. Large dams are expensive and have their own problems. But there are turbines now available which can function without the need of a dam; they incorporate integral pumps so that flowing water can provide a certain amount of energy to pump itself higher and thus provide for irrigation and water supplies. Archimedes developed one of the earliest types; the Chinese and the Swedes have developed more efficient ones. Figure 1 shows a Swedish version and Figure 2, a Chinese one.

Summarizing briefly, the market for small hydro development in the developing countries is difficult to determine precisely but could, in terms of capacity, range between 157 and 470 GW. The Third World demand for energy is not always properly satisfied by the supply of electricity, and finally, where autonomous hydroelectric schemes are planned they may be excessively expensive because of the poor load factor. Anyone who is interested in selling to the Third World need not worry about the market potential; but he will fail to move into it effectively without considering what village communities need to survive.

REQUIREMENTS OF THE DEVELOPED COUNTRIES

Developed countries, too, can provide a substantial market. The United States is one both near and enormous. However, we need to apply quite different criteria to determine the economic value of small hydro power. For the developed world, small hydro stations fall roughly into two categories. One, is that used to supply a community so far from the grid that connection would be too costly. The other is where the station may be used to supplement the grid or act as a standby. The first category generates a difficult question: How far from the grid is "too costly"? It depends on two related elements: the load factor and the nature of the grid supply. This material (Figure 3), presented by C. Head at the First European Conference on Small Hydro in 1982, shows how important the load factor is, a point I made earlier about the developing countries. The critical distances may vary a little from country to country, the nature of the grid (Figure 4) and from time to time, but the general shape of the curves matches most circumstances.

But there is a third element here that is often taken as a fixed and unalterable component - that is, cost. It is really quite easy to assess the cost of setting up a small-scale hydro plant, compare it with the cost of a similar diesel, or a grid connection, and than make what appears to be the most economical choice. This kind of accounting is wrong, partly because inflation is neglected, and the life of a hydro plant is often taken to be absurdly short.

Loans made for the installation of small-scale hydro are often badly calculated because neither inflation nor length of service is properly assessed. Unit cost is based on paying back the investment over a fixed period of time at some fixed rate of interest which may be anything from 8 to 15 per cent. Suppose for a small scheme - and the smaller the scheme, the higher the unit cost will be - the unit cost is 7 cents/kWh, perhaps 2.5 times the unit cost from the grid in this country. Few people would be willing to make this payment. If the loan were repaid over 15 years with inflation running at, say, 8 per cent then the actual value of that 7 cents would have fallen to 2.1 cents at the end of the term, even in the unlikely event that the load factor would not have improved during that time. The cost to the consumer on the conventional grid will continue to rise with inflation and at some point in the payback period, the cost of electricity from the grid will equal that from the small station and then swing in favour of the small station. And what happens after the loan is paid off?

Clearly, the traditional way of financing does not properly reflect the real economic benefits of the system, and, in fact discourages the implementation of small resources. Returning again to the comparison of small hydro versus grid connection, based on real-world economics, the actual distance at which

small hydro is economic is much closer to the grid than is commonly calculated (Figures 5 & 6).

One other point about the skewed economics was also made by Head at that confererence: the load factor will tend to improve with time and with the availability of local energy supply. Again this tilts the balance further towards small hydro.

Turning now to the second category of stations in developed countries, it is only possible to make a few general observations; costs are much more difficult to determine because there are many more variable factors. How important is reliability to the consumer? Can it provide reactive power? There are no general answers but there are some general points which can be made.

In the developed countries, peak electricity is more expensive than base electricity. In many of these countries (France is one, the UK is another) stream flows are at their maximum in the winter - the season of peak demands. The contribution that small hydropower can make to the grid - either by taking a few consumers off it at peak periods, or by adding small amounts of energy at this time - is not just the cost of the units but the savings made by not having to keep one or two large sets on standby for 12 or 18 hours to operate for 30 minutes.

What, then, are the constraints that operate against developing small hydro more effectively and more pervasively on a world-wide basis? Specifically, ignorance of actual Third World needs, and generally inappropriate accounting procedures. Overcoming the first problem requires considerable effort by manufacturers interested in selling to he Third World. It is of little use talking to the centralized authorities of the countries concerned whose priorities may have political or strategic dimensions. The aid agencies often know more about local needs than the state. They are the best source of accurate and useful information about local needs. Their information is often so accurate that they are thrown out of the host country for making it public. The problem is that the funding may be in the hands of the state, and this can present the engineer or manufacturer with a difficult choice: to install something that might not be appropriate and will eventually fall into disuse (but for which he will get paid), or to install something which is useful in the short and long term but for which there is no funding. However, the World Bank and its affiliates have been developing a much more sympathetic view of small-scale projects, and it is to these that the entrepreneur ought to direct his energies.

Another related difficulty is to convince governments that large schemes are not always the best choice. There was talk once of building Grande Inga in Zaire - 33,500 MW for a scattered rural population of 26 million.

The answer to our ignorance about the Third World may be to invest, either as individual firms or jointly in bringing village or community workers - certainly not politicians - to meetings such as this, or to take them to pilot schemes. There is also a powerful need for manufacturers to develop small working models - small enough to fit into a briefcase - which could be taken to remote sites and simply suspended in stream to generate electricity. This arrangement (Figure 7), a model of a mill used in Germany until about 1950, is one possible candidate. Local materials could be used to make the floating element, and a small version of the turbine they are using in New York (Figure 8) could be suspended from it. The manufacturer would need to supply the turbine and the generator and perhaps a storage cooker - this one (Figure 9) consumes 200 W - and he could do away with drawings and interpreters. Of course, it is not quite as simple as this, but nevertheless the process can do more to spread ideas than most elaborate discussions.

The second major impediment, that is, inappropriate accounting, is more to do with the developed countries. Inflation works in favour of renewable energy schemes, and any costing which fails to take this into account is erroneous. Similarly, any loan which extends for just ten years for a hydro plant is short-sighted. The comparison between small hydro, grid connection or diesel power must be based on reality, not on theory.

A lot of effort by people in this audience will be needed to correct present misapprehensions.

Fabian Acker is a consultant to International Waterpower and Dam Construction.

Table 1

SHP development in some Asian countries

Country	No. of stations	Installed capacity (MW)
Bangladesh	12 sites proposed for feasibility studies	
Burma	29 sites under study	
	7 under construction	6.95
China	74 000 in operation	9 000
India	88	530
Indonesia	50 in operation	31
	10 under construction	7
	291 potential sites	1 340
Malaysia	11 before 1945	
	22 pilot stations completed since 1980	
	82 sites studied	
Nepal	10	1.824
	17 under construction	6.688
	10-15 under study	
Pakistan	15	2.23
Philippines	11 in operation	13
	17 under construction	14.736
	45 detailed engineering	49
	95 feasibility studies	131
Sri Lanka	30	1.8
	15 under construction	4.5
	140 sites identified	95
Thailand	20 in operation	5
	25 under construction	17

Source: Zhu Xiaozhang, 2nd International Conference on Small Hydro, China, April 1986.

Table 2

Expected small hydro potential in EEC

	Output (GWh)	Power (MW)
Belgium	400	70
France	7000	1200
Greece	1500	250
Italy	6000	1000
United Kindom	1000	170
West Germany	1500	250
(Portugal)	4000	650
(Spain)	4400	750

Source: EEC Commission, Direction XVII/E2

Figure 1

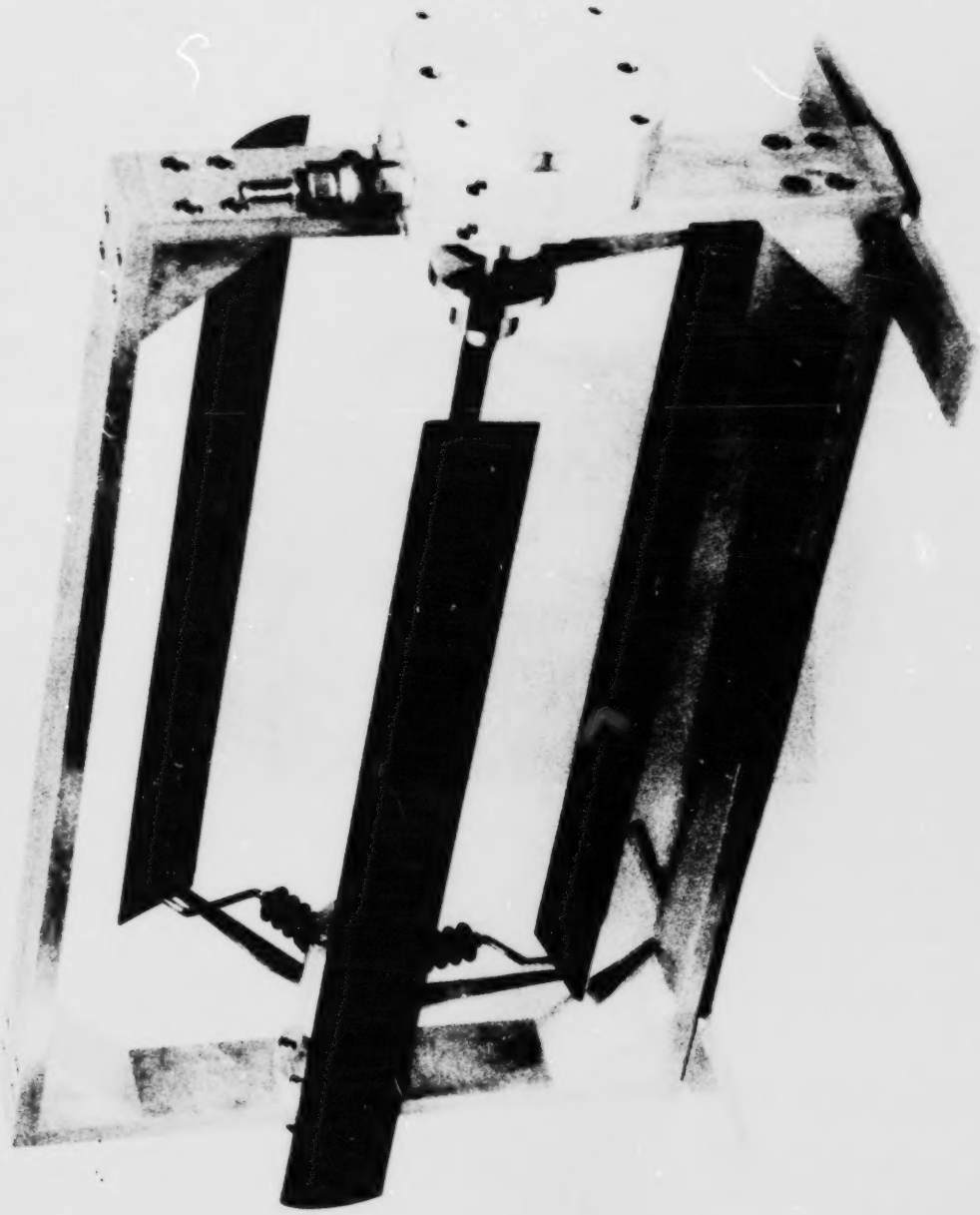


Figure 2

Figure 3

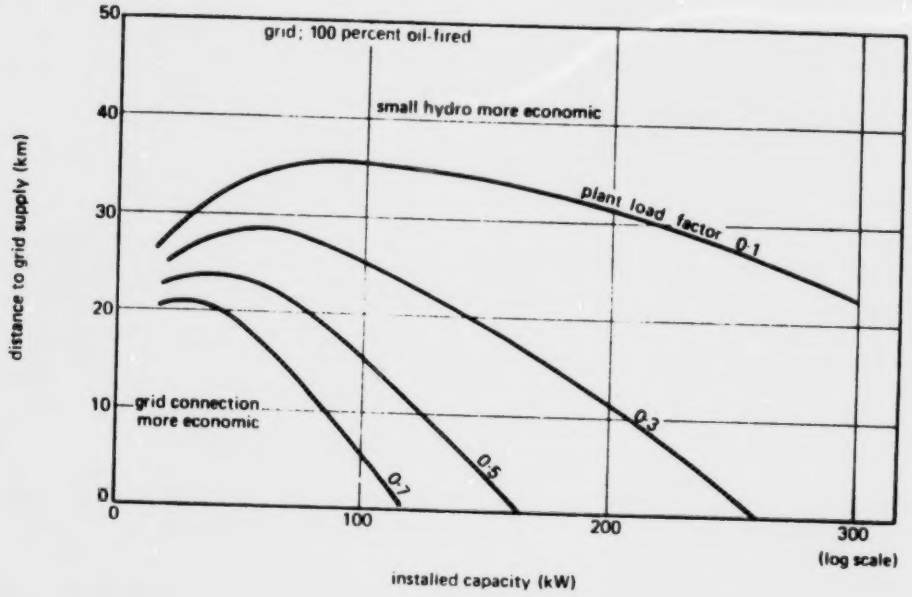


Figure 4

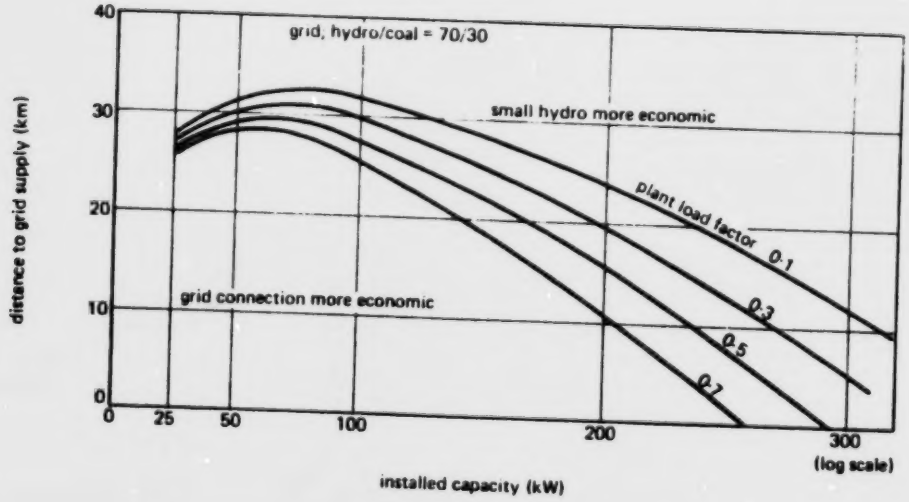


Figure 5

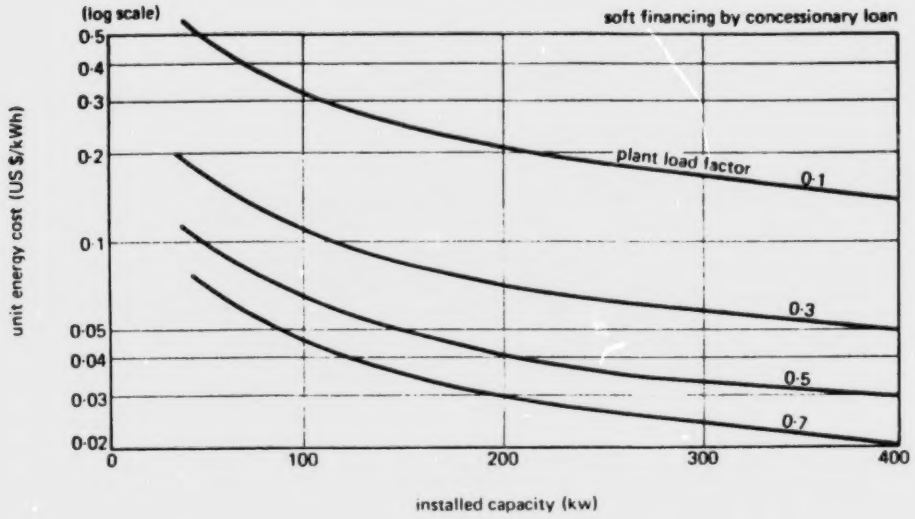


Figure 6

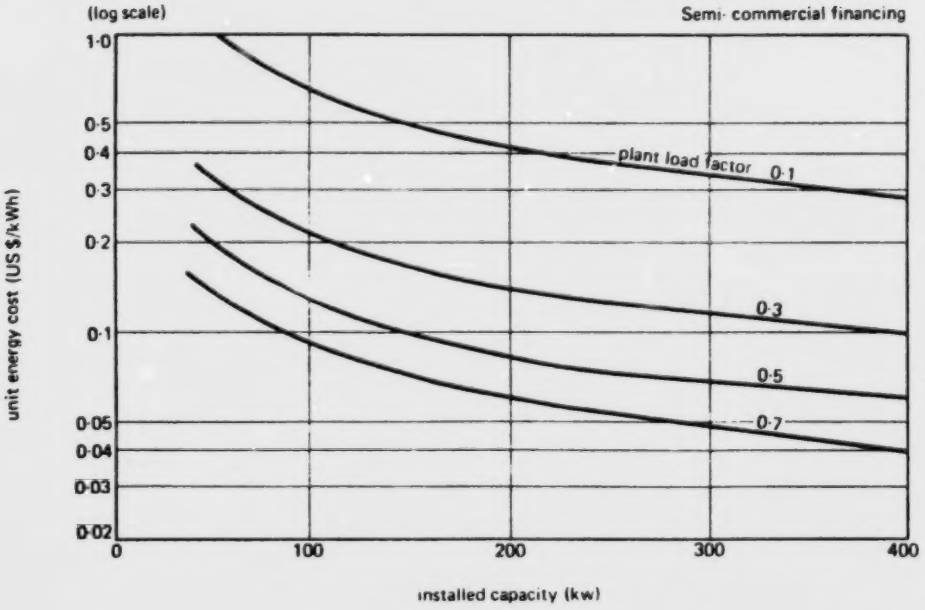


Figure 7

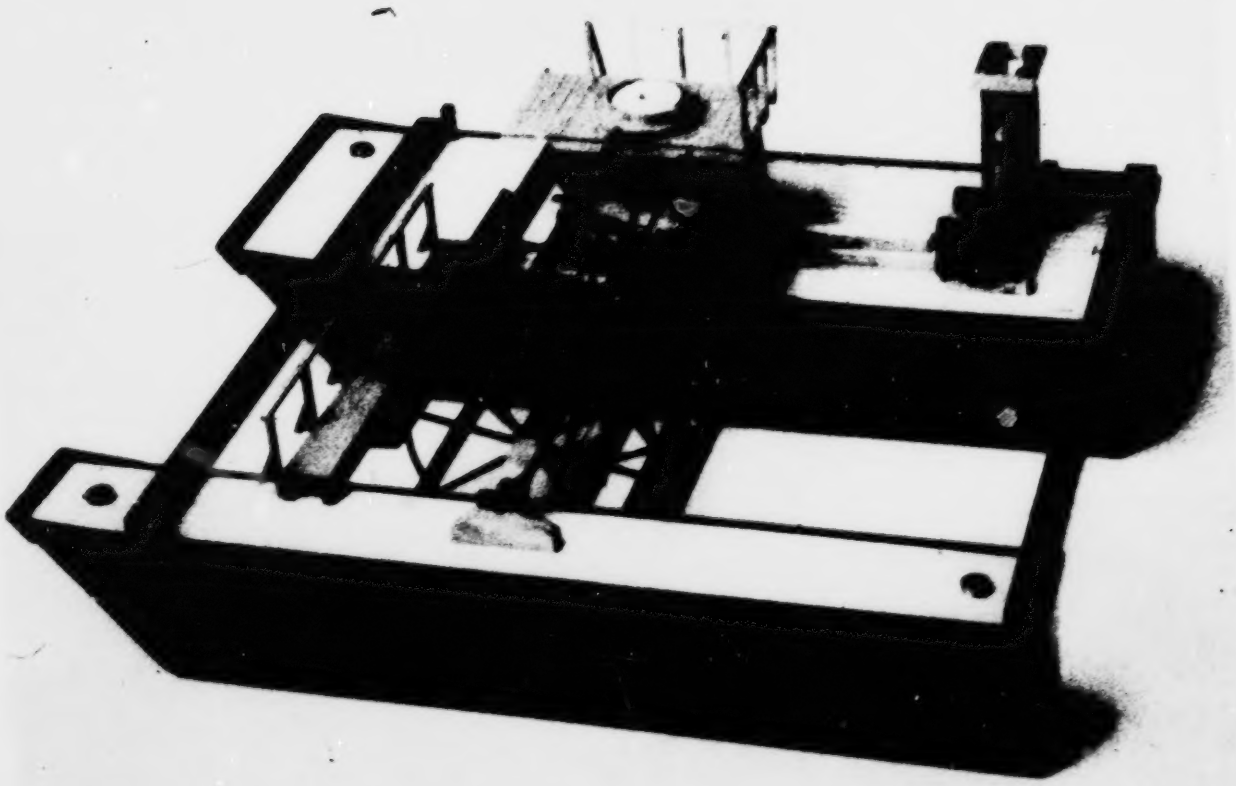
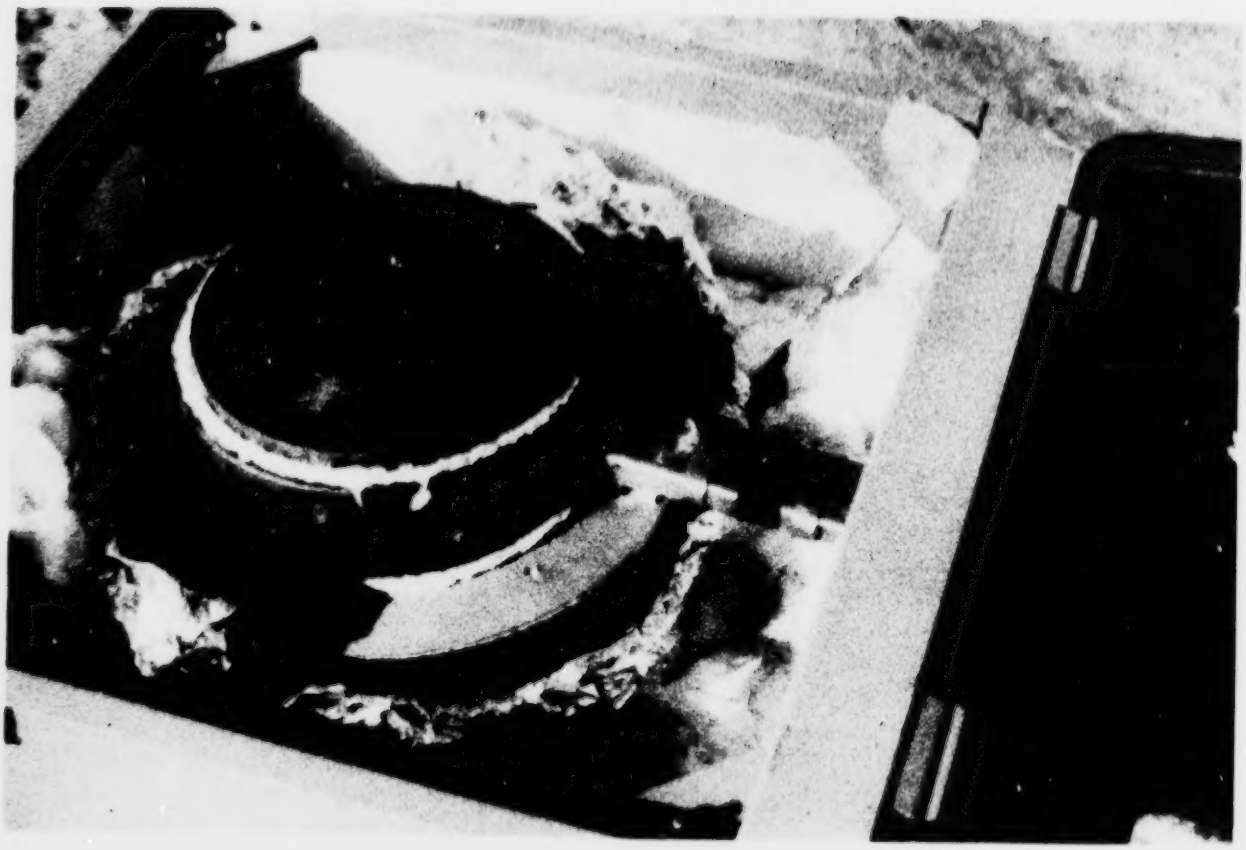


Figure 8

Figure 9



SMALL HYDRO

CANADIAN TECHNICAL POTENTIAL AND THE MARKET

Charles Figueiredo
Policy Consulting Group
Energy and Environmental Research and Analysis
Toronto, Ontario

INTRODUCTION

This paper provides a quantitative estimate of the technical potential[1] for small hydro power in the provinces, territories and Canada as a whole[2]. The paper summarizes the views of the various provincial authorities on how they believe the small hydro market will develop over the near term. Finally, the paper will discuss some of the strategies which need to be strengthened or implemented if the market for small hydro in Canada is to expand over the short and medium term.

The estimate of potential presented here was derived through the integration of existing site information extracted from various published and unpublished evaluations of small hydro potential[3]. This existing site information, and the paper's estimate of potential, exclude information on technical potential at unknown sites which have not been surveyed because of the high cost of the comprehensive site surveys which would be required to obtain information about them. Also excluded is information on small hydro potential at known sites which have not been appropriately surveyed because researchers deemed them to be excessive distances from loads or the termini of electrical grids. In the evaluation of small hydro potential, excessive distance from loads or the termini of grids is taken to be prima facie evidence for the fact that a site cannot be economically developed.

THE TECHNICAL POTENTIAL FOR SMALL HYDRO IN CANADA

The definition of the power output range that is to be used in evaluations of small hydro potential varies from province to province and from study to study. In Ontario, anything below 20 MW is considered small. Quebec's major study[4] on small hydro sites considers anything under 100 MW to be small. While in Prince Edward Island, anything under 5 MW is considered small. For this reason, the numbers and kinds of sites for which information exists and the manner in which this information is made available for analysis also vary from province to province.

This paper has avoided the task of defining what should constitute small hydro by organizing, integrating and massaging the existing site-based information on small hydro potential under four capacity classes.

Class A: up to 10 Megawatts
Class B: greater than 10 and up to 20 Megawatts
Class C: greater than 20 and up to 30 Megawatts
Class D: greater than 30 and up to 40 Megawatts

The results of this analysis are presented and discussed below[5] in terms of average Megawatts of available potential.

GLOBAL POTENTIAL

The derived estimates of Canadian small hydro potential by each of the four capacity classes for the provinces and the territories are presented in Table 1.

- The provinces with the greatest technical potential in Capacity Class A are Ontario (500 MW), New Brunswick (385 MW), Quebec (384 MW), and Newfoundland (235 MW). These provinces account for approximately 32% of Canada's 1808 MW[6] of Class A potential. With the exception of B.C. (240 MW of Class A potential), Western Canada does not appear to have significant Class A small hydro potential.

- The relative Class A potentials for the provinces are graphically depicted in Figure 1

- In Capacity Class B, Quebec (665 MW), Ontario (200 MW) and Newfoundland (121 MW) account for approximately 90% of the 1098 MW of potential in Canada.

- Small hydro potential in Capacity Classes C and D is dominated by Quebec which accounts for approximately 95% (1831 MW) of Class C and 90% (560 MW) of Class D potential, respectively. This may simply be due to the fact that since any sites with potentials greater than 20 MW are not deemed to be 'small' under the definitions used by studies in the other provinces, they have not been surveyed.

A graphical depiction of the potential in each of the four capacity classes for Canada as a whole is presented in Figure 2. Class A and Class B potentials account for 33% and 20% of Canadian potential at sites up to 40 MW in capacity, respectively.

The effect on estimates of potential in combined capacity classes is set out in Table 2.

- Quebec (1029 MW), Ontario (700 MW), New Brunswick (385 MW) and Newfoundland (356 MW) account for 90% of Canadian small hydro potential (2906 MW) at sites up to 20 MW in capacity.

The relative combined Class A and B potentials for the provinces are graphically depicted in Figure 3.

Information on the number of sites that account for the potential set out in Tables 1 and 2 and Figures 1, 2 and 3 is presented in Table 3.

- Ontario (714) and B.C. (719) are estimated to have the largest number of Capacity Class A sites, together accounting for approximately 75% of the sites in this class (also see Figure 4).

- Sites in Quebec (58) account for most (60%) of the Class B sites (also see Figure 5).

Estimates of the average capacity of sites in each capacity class by province and territory are provided in Table 4. The estimates of average site capacity should be treated with caution because of uncertainty about the representativeness of the sites from which the information has been generated.

- Quebec (4.5 MW), Saskatchewan (3.7 MW), Newfoundland (3.2) and Alberta (3.1 MW) have the highest average capacity Class A sites. The average capacities of provincial and territorial Class A sites are graphically depicted in Figure 6.

- Newfoundland (15.2 MW) and Alberta (14.5 MW) have the highest average capacity Class B sites (also see Figure 7).

REMOTE VS GRID-LINKED POTENTIAL

Estimates of the remote vs grid-linked potential for small hydro by province and capacity class are presented in Table 5. A graphical depiction of the potential at remote vs grid-linked Class A and Class B sites by province are presented in Figure 8 and Figure 9, respectively.

- The potentials at Class A remote and grid-linked sites for Canada as a whole are approximately 600 MW (33% of Class A potential) and 1208 MW (63% of Class A potential), respectively. Among Class A sites, almost all provinces have greater grid-linked than remote potential (see Figure 8).

- The potentials at Class B remote and grid-linked sites for Canada as a whole are approximately 258 MW (23 % of Class B potential) and 840 MW (77% of Class B potential) respectively (see Figure 9).

- The potential at remote sites up to 20 mw in capacity for Canada as a whole is approximately 859 MW (30% of combined Class A and B potential); while the potential at grid-lined sites is approximately 2047 MW (70% of combined Class A and B potential) (see Figure 10).

THE ECONOMIC POTENTIAL AND THE MARKET FOR SMALL HYDRO IN THE NEAR TERM

Meaningful empirically derived estimates of how much of the technically available potential for small hydro can be economically developed, and is likely to be developed, are difficult to derive without undertaking economic evaluations of the sites which provide this technical potential.

Qualitative insights into how the Canadian small hydro market is expected to develop can be provided. These are based upon the perceptions of relevant provincial authorities. The perceptions of provincial authorities are important because they are likely to influence the extent to which the market is seen to be risky, and the extent to which it does in fact develop. The reasons for this will be outlined below in the discussion about strategies to promote the expansion of the market.

THE WEST

Small hydro authorities in the west deem almost all the small hydro potential to be uneconomic, and the market for small hydro in the Western provinces is expected to be relatively stagnant over the near term.

A number of factors work against the expansion of the market in the west. The significant surplus of generating capacity which exists in the west, particularly in B.C., works against the development of grid-linked potential; and ongoing and anticipated declines in the world price of petroleum are a dis-incentive to the development of remote hydro sites. In addition, although most Western provinces have policies on buy-back rates for small hydro[7], they do not have active policies to promote the delineation of the small hydro resource base or the expansion of the market.

In the West, a good deal of the small hydro activity that has occurred in recent years has been driven by federally-funded resource base identification and development programs.

CENTRAL CANADA

In Quebec, provincial government authorities deem approximately 300 MW of potential to be economically attractive. Nevertheless, the market for small hydro in Quebec is not expected to grow appreciably over the near term because of the province's strong interest in, and commitment to, large hydro-electric facilities, and the absence of an explicit policy to promote small hydro. In addition, although Hydro Quebec does have a policy on buy-back rates for parallel generation, it does not have any specific policy on buy-back rates for small hydro generation.

In Quebec, the federal Department of Energy Mines and Resources has played the central role in development of small hydro in recent years through its funding of demonstration projects.

In Ontario, the market is expected to expand even though Ontario Hydro, operating with a significant generating surplus, does not deem much (20 MW) of the available potential to be economically attractive. The Ontario Ministry of Energy has targeted 100 MW as the amount of new small hydro to be installed by 1995, and it is the only provincial authority to have done so. Most of the growth in the market in recent years has occurred in the context of active policy-level support for small hydro, primarily by the Ministry of Energy, and secondarily by the federal Department of Energy Mines and Resources. This policy-level support is likely to be critical to the expansion of the market in Ontario.

EASTERN CANADA

The market is expected to be relatively stagnant in P.E.I. and Nova Scotia.

P.E.I. is not deemed to have much potential because of the low heads of sites available in the province[8]. What potential does exist is not deemed to be economic.

Nova Scotia is deemed not to possess very much additional potential which can be economically developed over the near term.

In New Brunswick, the market is expected to expand because of increasing entrepreneurial interest in small hydro and increased policy level interest in small hydro on the part of provincial authorities.

The grid-linked small hydro market in Newfoundland is expected to expand over the next five years even though Newfoundland Power and Light deems most of the potential to be uneconomic. However, the expansion of the remote small hydro market is thought to be extremely unlikely because of the province's policy of subsidizing diesel-generated electricity at remote sites to the level of grid-fed electricity.

PROMOTING THE EXPANSION OF THE MARKET FOR SMALL HYDRO

It is no accident that the provinces in which there has been little or no growth in the small hydro market in recent years are also the provinces in which there are no explicit policies on or active public sector support for small hydro[9]. The prospects for growth in the Canadian small hydro market over the near term are likely to be considerably brighter if public sector strategies for the promotion of small hydro are implemented or strengthened. A number of these strategies are briefly discussed below:

- The design and implementation of a straightforward and streamlined process for obtaining the necessary approvals will go a long way towards fostering the development of small hydro sites by small entrepreneurs. Conversely, complex and fragmented approvals procedures will work against an expansion of the market. Not only do complex approvals procedures increase the real possibility of a project being delayed, and perhaps rendered economically unattractive, but they also increase the perception that approval for a project is too difficult or frustrating to obtain.

- The development of a public sector policy-level consensus on the attractiveness of small hydro, its importance to the energy mix of a jurisdiction, and the manner and degree to which it is to be actively supported is also of critical importance to the expansion of the market. Policy level disagreements between provincial ministries and utilities increase uncertainty among prospective developers of small hydro, and undermine prospects for market expansion.

- The implementation of equitable and explicitly articulated policies on public sector support for small hydro vis-a-vis other sources of generation is of significant importance to the expansion of the market. The implementation or continuation of policies that are not clearly articulated, which extend unbalanced subsidies to alternative sources of generation (e.g., unbalanced subsidies to diesel-generated power at remote locations), or which undermine a project's ability to sell surplus power (e.g., minimal utility buy-back rates) are likely to severely constrain the expansion of the market.

  Policies to allow for the funding of prefeasibility studies and the extension of financing support will be of particular importance to the expansion of the market.

- The rationalization of the system by which information is gathered and disseminated is also of importance to the expansion of the market. Multi-channelled, convoluted or fragmented information systems are frustrating to prospective small hydro entrepreneurs.

  In this context, the development of an effective educational capability within the information dissemination system is also of particular importance to the expansion of the market.

- The ongoing delineation of the extent of small hydro potential is also of importance to the expansion of the market. Reliable information on potential is usually an important pre-requisite to the development of any market.

CONCLUSION

Canada has significant small hydro potential amounting to approximately 2 GW and 3 GW of capacity at sites up to 10 and 20 MW in size, respectively[10]. This is equivalent to approximately 8% of the currently installed hydraulic capacity in Canada (55 GW).

Existing information suggests that there is appreciable potential in Quebec, Ontario, New Brunswick, Newfoundland and British Columbia at Class A sites (up to 10 MW). Potential also exists in Ontario and Quebec at Class B sites.

The small hydro market is not expected to expand appreciably in the Western provinces, Quebec, P.E.I., or Nova Scotia. In Ontario, Newfoundland and New Brunswick, the market is expected to grow although no quantitative estimates can be provided as to how much growth will occur. Provincial uthorities deem perhaps 500 - 600 MW of potential at sites up to 20 MW in size to be economically attractive. Tung has estimated that 100-150 MW (equivalent to 2-3% of currently installed hydraulic capacity) of potential at sites up to 10 MW in size are likely to be implemented over the short and medium term.

The strengthening or implementation of explicit public sector strategies to promote small hydro will have a critical impact on the manner in which and the degree to which the small hydro market will expand in the short and medium term in Canada.

Charles Figueiredo is a Ph.D. candidate in Policy Analysis at York University. He currently holds a part-time appointment as Assistant Professor (Energy Studies) in the York Graduate Faculty. Mr. Figueiredo has authored or co-authored thirteen professional papers, reports, and publications.

Table 1

Estimate of Small Hydro Potential in Megawatts
By Jurisdiction and Capacity Class

Jurisdiction		Capacity Class				
Name	Code	A	B	C	D	All
Alberta	1	15.4	29.0	27.5	0.0	71.9
B.C.	2	240.0	60.0	0.0	0.0	300.0
Manitoba	3	12.8	0.0	0.0	0.0	12.8
New Brunswick	4	385.0				385.0
Newfoundland	5	234.9	121.5	31.1	0.0	387.5
Nova Scotia	6					
N.W.T.	7	26.9	0.0	0.0	0.0	26.9
Ontario	8	500.0	200.0	0.0	0.0	700.0
P.E.I.	9	7.2				7.2
Quebec	10	364.5	665.2	1831.4	560.0	3421.1
Saskatchewan	11	18.7	22.0	56.0	72.0	168.7
Yukon	12	3.0	0.0	0.0	0.0	3.0
Canada	13	1808.4	1097.7	1946.0	632.0	5484.1

Table 2

Estimate of Small Hydro Potential in Megawatts
Cumulative by Capacity Class

Jurisdiction		Capacity Class			
Name	Code	A	A-B	A-C	A-D
Alberta	1	15.4	44.4	71.9	71.9
B.C.	2	240.0	300.0	300.0	300.0
Manitoba	3	12.8	12.8	12.8	12.8
New Brunswick	4	385.0	385.0	385.0	385.0
Newfoundland	5	234.9	356.4	387.5	387.5
Nova Scotia	6				
N.W.T.	7	26.9	26.9	26.9	26.9
Ontario	8	500.0	700.0	700.0	700.0
P.E.I.	9	7.2	7.2	7.2	7.2
Quebec	10	364.5	1029.7	2861.1	3421.1
Saskatchewan	11	18.7	40.7	96.7	168.7
Yukon	12	3.0	3.0	3.0	3.0
Canada	13	1808.4	2906.1	4852.1	5484.1

Table 3

Estimate of Number of Small Hydro Sites
By Jurisdiction and Capacity Class

Jurisdiction		Capacity Class				
Name	Code	A	B	C	D	All
Alberta	1	5	2	1	0	8
B.C.	2	719	6	0	0	725
Manitoba	3	8	0	0	0	8
New Brunswick	4	154	0	0	0	154
Newfoundland	5	74	8	1	0	83
Nova Scotia	6					
N.W.T.	7	6	0	0	0	6
Ontario	8	714	14	0	0	728
P.E.I.	9	6				6
Quebec	10	140	58	67	16	281
Saskatchewan	11	5	2	2	2	11
Yukon	12	2	0	0	0	2
Canada	13	1833	90	71	18	2012

Table 4

Estimate of Average Site Capacity (MW)
By Jurisdiction and Capacity Class

Jurisdiction		Capacity Class				
Name	Code	A	B	C	D	All
Alberta	1	3.1	14.5	27.5		9.0
B.C.	2	0.3	10.0			0.4
Manitoba	3	1.6				1.6
New Brunswick	4	2.5				2.5
Newfoundland	5	3.2	15.2	31.1		4.7
Nova Scotia	6					
N.W.T.	7	4.5				4.5
Ontario	8	0.7	14.4			1.0
P.E.I.	9	1.2				1.2
Quebec	10	2.6	11.5	27.3	35.0	12.2
Saskatchewan	11	3.7	11.0	28.0	36.0	15.3
Yukon	12	1.5				1.5
Canada	13	1.0	12.2	27.4	36.0	2.7

Table 5

Remote vs. Grid-Linked Small Hydro Potential in Megawatts
by Jurisdiction and Capacity Class

Jurisdiction			Capacity Class				
Name	Code		A	B	C	D	All
Alberta	1	Total	15.4	29.0	27.5	0.0	71.9
		Remote	3.0	15.0	27.5	0.0	45.5
		Grid-Linked	12.4	14.0	0.0	0.0	26.4
B.C.	2	Total	240.0	60.0	0.0	0.0	300.0
		Remote	36.5	12.0	0.5	0.0	48.5
		Grid-Linked	203.5	48.0	0.0	0.0	251.5
Manitoba	3	Total	12.8	0.0	0.8	0.0	12.8
		Remote	12.8	0.0	0.0	0.0	12.8
		Grid-Linked	0.0	0.0	0.0	0.0	0.0
New Brunswick	4	Total	385.0	0.0	0.0	0.0	385.0
		Remote	154.0	0.0	0.0	0.0	154.0
		Grid-Linked	231.0	0.0	0.0	0.0	231.0
Newfoundland	5	Total	234.9	121.5	31.1	0.0	387.5
		Remote	88.8	46.2			135.0
		Grid-Linked	146.1	75.3	31.1	0.0	252.5
Nova Scotia	6	Total					
		Remote					
		Grid-Linked					
N.W.T.	7	Total	26.9	0.0	0.0	0.0	26.9
		Remote	26.0	0.0	0.0	0.0	26.9
		Grid-Linked	0.0	0.0	0.0	0.0	0.0
Ontario	8	Total	500.0	200.0	0.0	0.0	700.0
		Remote	200.0	120.0	0.0	0.0	320.0
		Grid-Linked	300.0	80.0	0.0	0.0	380.0
P.E.I.	9	Total	7.2	0.0	0.0	0.0	7.2
		Remote	0.0	0.0	0.0	0.0	0.0
		Grid-Linked	7.2	0.0	0.0	0.0	7.2
Quebec	10	Total	364.5	665.2	1831.4	560.0	3421.1
		Remote	56.9	42.5	71.3	560.0	730.7
		Grid-Linked	307.6	622.7	1760.1	0.0	2690.4
Saskatchewan	11	Total	18.7	22.0	56.0	72.0	168.7
		Remote	18.7	22.0	56.0	72.0	168.7
		Grid-Linked	0.0	622.7	1760.1	0.0	0.0
Yukon	12	Total	3.0	0.0	0.0	0.0	3.0
		Remote	3.0	0.0	0.0	0.0	3.0
		Grid-Linked	0.0	0.0	0.0	0.0	0.0
Canada	13	Total	1808.4	1097.7	1946.0	632.0	5484.1
		Remote	600.6	257.7	154.8	632.0	1645.1
		Grid-Linked	1207.8	840.0	1791.2	0.0	3839.1

Figure 1

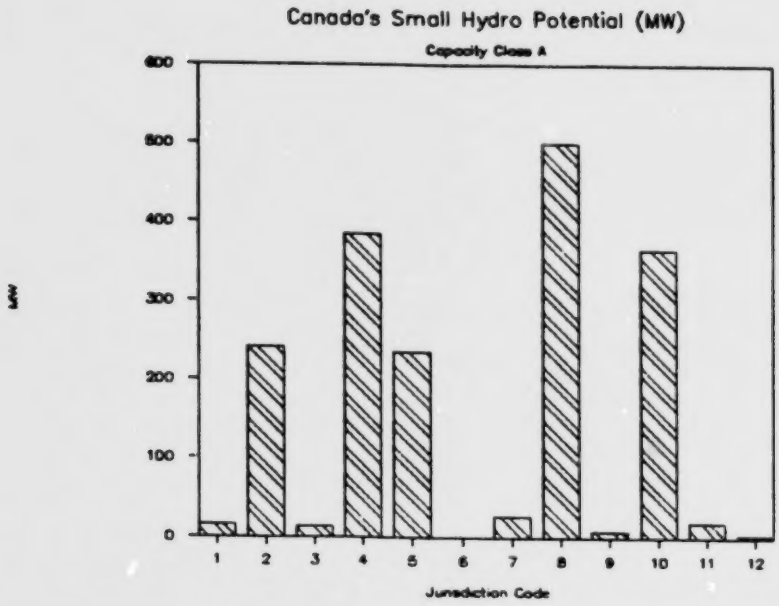


Figure 2

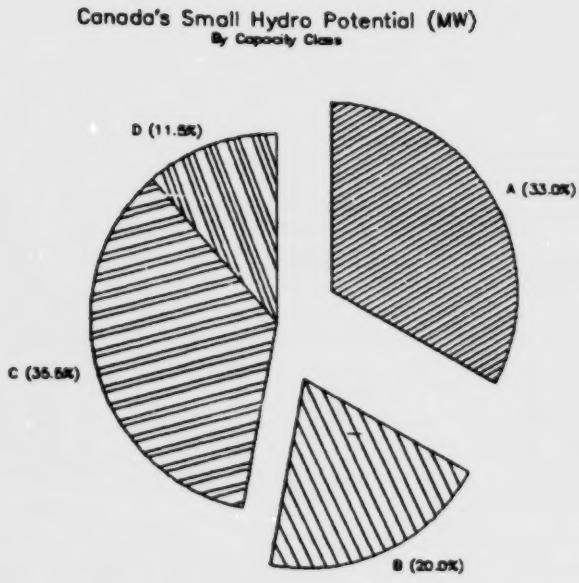


Figure 3

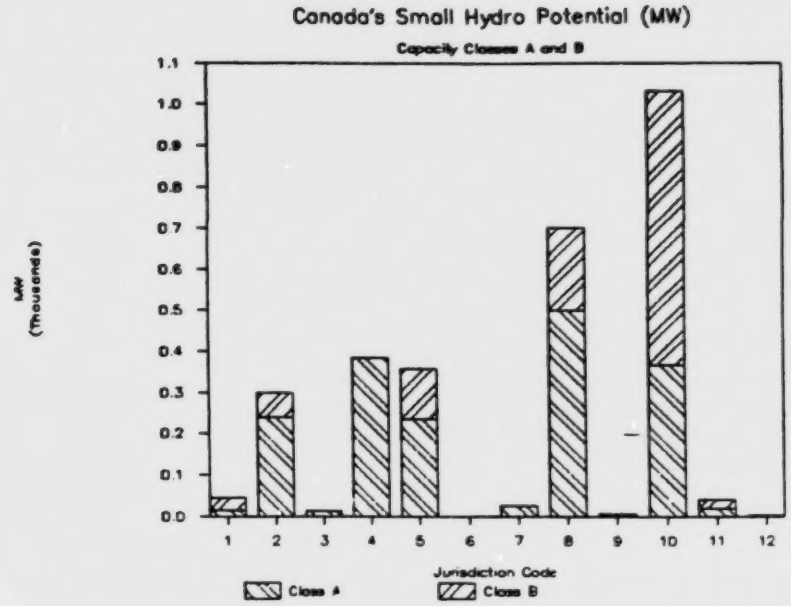


Figure 4

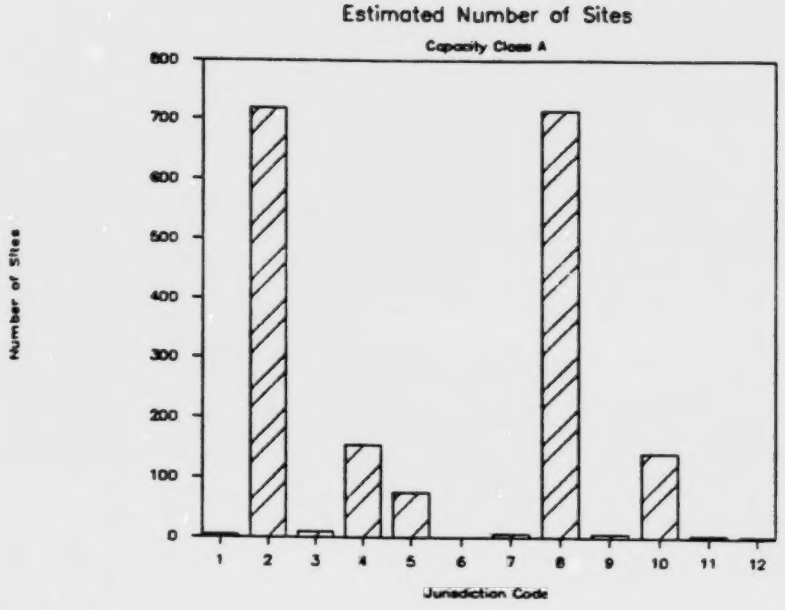


Figure 5

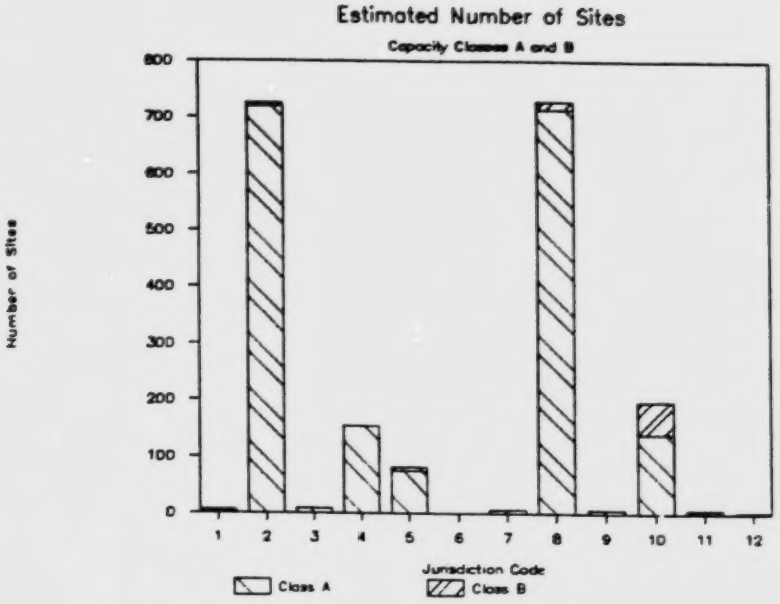


Figure 6

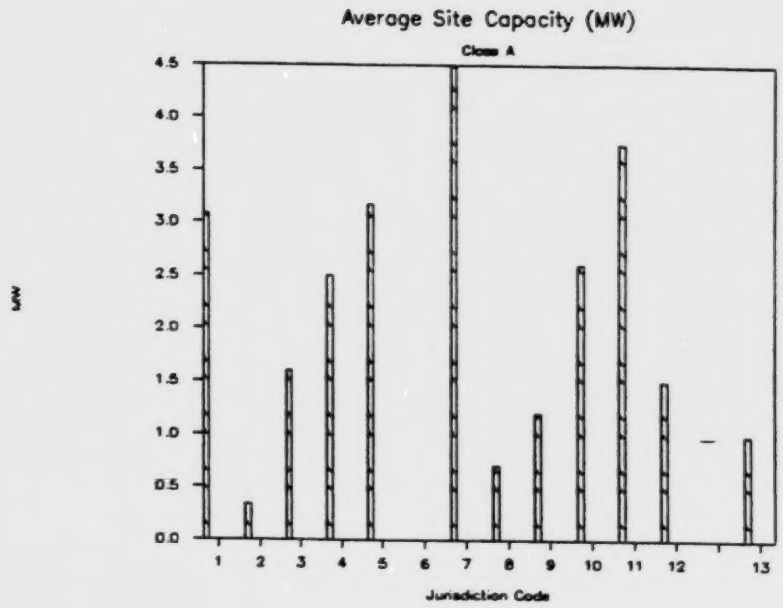


Figure 7

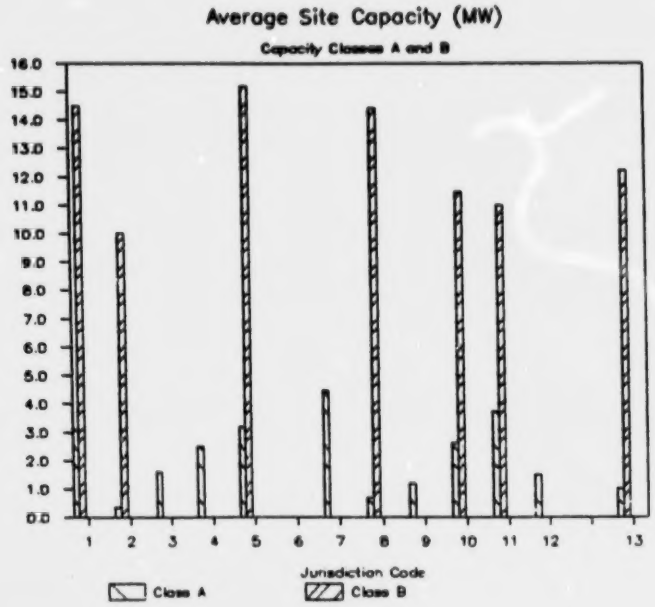


Figure 8

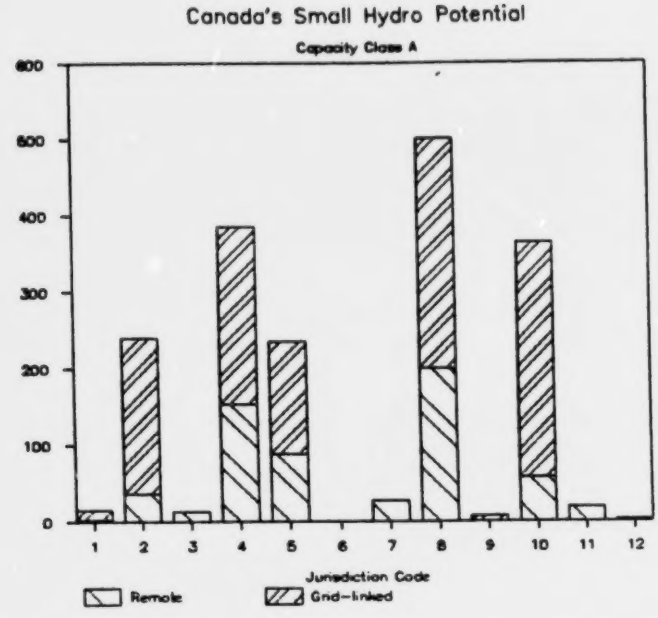


Figure 9

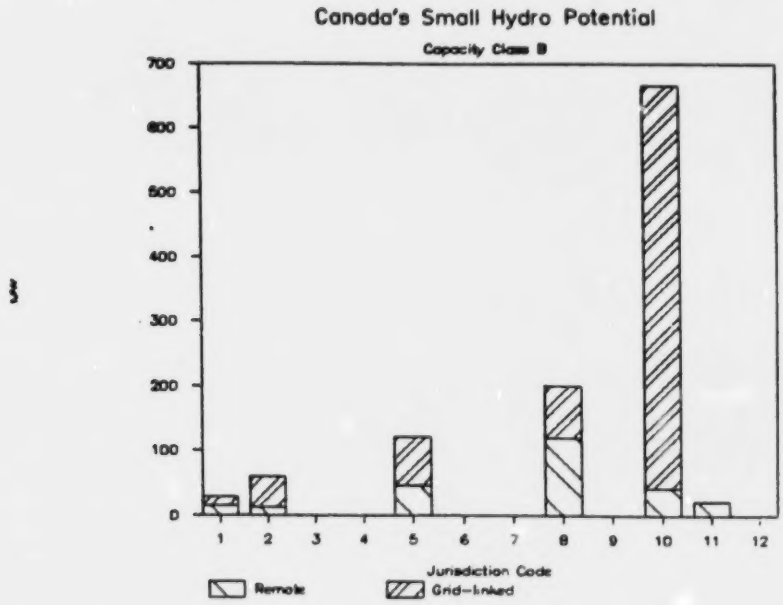
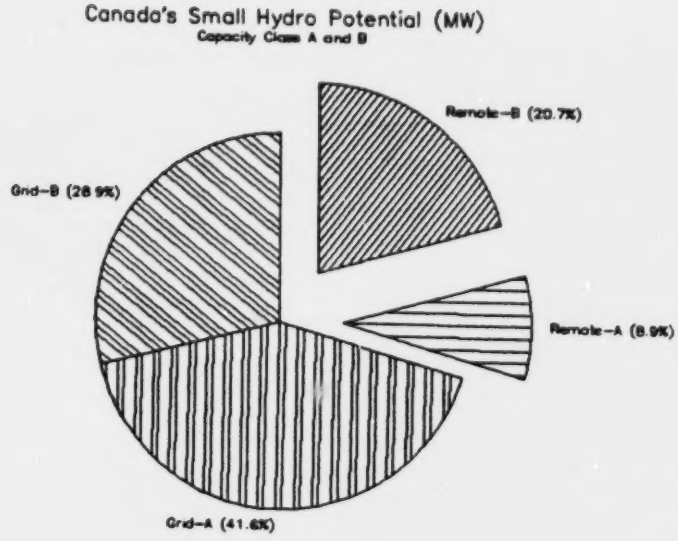


Figure 10



NOTES

1. Ideally, an assessment of the extent to which small hydro is exploitable (the potential), or is likely to be exploited (the market), should expend varying levels of effort in the derivation of at least five different interdependent levels of potential.

A. Theoretical Potential

An estimate of theoretical potential would reveal how much small hydro power would be available if there were no technological, economic, institutional or environmental barriers to its exploitation.

Estimates of the theoretical availability of small hydro can be derived through either.. (1) predominantly analytical techniques in the form of models or formulae (e.g., the Gordon-Penman capacity estimating formula) which use the watershed as their standard unit; or (2) predominantly empirical techniques in the form of comprehensive inventories of small hydro sites.

Analytically derived estimates of theoretical potential are generally only indicative because of the critical importance of site characteristics on small hydro potential. Although such estimates are not ones upon which implementation programs can be contemplated, they are useful ones to have because they provide a basis upon which to further the assessment of the resource base and the expansion of the market by, for example, allowing the most promising watersheds to be targeted for more detailed evaluation.

In the case of small hydro, meaningful comprehensive estimates of theoretical potential, either analytically or empirically derived, are unavailable for Canada and most of its regions. The models and data necessary to their analytical derivation are only now being integrated, computerized and implemented: and the comprehensive site inventories necessary to their empirical derivation do not exist for all regions because of the high cost (in both time and money) of conducting these inventories.

B. Technical Potential

An estimate of technical potential would reveal how much of the theoretically available small hydro power is actually exploitable given the technology and e"gineering available at the time of the estimate. Technical potential can be estimated through the application of technical and engineering constraint analysis to analytical or empirical estimates of theoretical potential.

This paper does not provide any comprehensive estimates of technical potential since comprehensive estimates of theoretical potential are themselves not available.

C. Economic Potential

An estimate of economic potential would reveal how much of the technically available small hydro power is actually exploitable given the economic constraints associated with bringing it into production.

In the case of small hydro, it is difficult to obtain a meaningful overall quantitative estimate of economic potential in the absence of the good site data. Small hydro is produced at discrete, widely dispersed and heterogeneous sites; and the most of the elements which apply in the case of small hydro are extremely site- and project-sensitive. Cost elements which apply to small hydro include: approvals; prefeasibility, design and engineering; site, generation facilities and civil works; transmission; legal and environmental impact mitigation.

Meaningful estimates of economic potential can only be derived through a comprehensive integration of the independent results of site- or project-specific evaluations of small hydro.

The paper does not provide any comprehensive quantitative empirical estimate of economic potential.

D. Environmentally Acceptable Potential

An estimate of environmentally acceptable small hydro potential would reveal how much of the economically exploitable potential is actually available given that development of some of sites may entail environmental impacts which cannot be made acceptable. This paper does not provide an estimate of environmentally acceptable small hydro potential.

E. Likely Potential

An estimate of likely potential would reveal how much of the environmentally acceptable small hydro will be brought into production. Likely, potential is constrained by the degree to which entrepreneurs see small hydro to be risky, the degree to which government programs make small hydro attractive and so on.

The paper summarizes the views of the various provincial authorities on what they believe the likely small hydro potential to be over the near term.

2. Power available from small hydro sites where construction of generation facilities and civil works are underway, or sites where power facilities are in service are not included in the estimates of potential presented in this paper.

3. Sources used in deriving the estimate of technical potential are set out in the reference list appended to the paper.

4. **Dossier Sur Les Petites Centrales**, Hydro-Quebec, 1980.

5. Note that some of what Quebec considers to be small hydro potential, potential at sites greater than 40 and up to 100 megawatts, are not included in this analysis.

6. Tung and Barclay estimate theoretical potential at sites up to 10 mW to be 2000 mW. Tung estimates that approximetely, 110 MW of Canada's currently installed hydraulic capacity (54,900 MW) is small in scale. In addition, he estimates that approximately, 100-150 MW of additional small hydro capacity is likely to be installed over the short and medium term.

7. Manitoba is the only Western province which does not have a policy on buy-back rates for small hydro.

8. According to Tung and Barclay, there is a possibility that low-head sites can be developed using Vertical Axis Hydraulic Turbines currently under development in Canada (op. cit., 4)

9. A useful survey-based analysis of the economic, institutional, environmental and technical constraints on the implementation of small hydro can be found in: W.W. Crumplin, **Assessment of Development of Small Hydroelectric Energy in Eastern Canada**, Energy, Mines and Resources Canada, 1986.

10. See Note 6.

SOURCES

The estimates of potential and comments on the market provided in this paper were informed by federal and provincial institutions responsible for energy-related matters in Canada, and by the sources set out below.

Acres Consulting Services, An Analysis of Constraints to Small Hydro Development in Ontario, Ontario Ministry of Energy, 1982.

Anderson, P.W. and Durnford, G.S., Study of Potential Small Hydro Sites in Newfoundland, Newfoundland Light and Power Company Ltd.

Crippen Consultants, Micro Hydro: A Survey of Potential Micro Hydro Developments of Use by Remote Communities in British Columbia, Volumes 1 and 2, Energy, Mines and Resources Canada, 1980.

Crumplin, William W., Assessment of Development of Small Hydro-Electric Energy in Eastern Canada, Department of Energy Mines and Resources Canaoa, 1986.

Demers, J.J., Potential Hydraulique Non Amenge Des Petites Centrales, Hydro- Quebec, 1980.

Department of Lands, Water Powers in British Columbia, Province of British Columbia.

Diddens, J.H., "Current Assessment of Prospects for Further Hydro Development in Canada", Canadian Water Resources Journal 6, 3, 63-83.

Everdell, R.A. and Near, F.M., "Provision of Energy Requirements for Remote Communities by Small-Scale Hydro Development", Canadian Water Resources Journal, 6, 3, 143-162.

Graham, D.S., "Status of Small Hydro-Electric Development in Ontario, Canada", Proceedings Waterpower '83, 1, 230-238, noxville, Tenn., 1984.

Greeley, A.W., Morris Development: Project Description, Newfoundland Power and Light Company, 1981.

Ministry of Natural Resources (Ontario), List of Water Powers for Ontario, draft, 1985.

Monenco Ltd., Identification of Environmentally Compatible Small-Scale Hydroelectric Potential in Atlantic Canada, Energy, Mines and Resources Canada, 1984.

Montreal Engineering Company Ltd., Small Hydro Study: St. Mary River Irrigation District, Transalta Utilities Corporation, 1982.

Moore, L., Small Hydro: A View of the Canadian National Scene, Annual National of the Solar Energy Society of Canada, August 2-6, 1984.

Nova Scotia Department of Mines and Energy, "Micro Hydro", Project Summary 003, Energy, Mines and Resources Canada, 1983.

Ontario Hydro, Hydraulic Power Resources of the Province of Ontario, Inventory Report 1982, Hydraulic Studies and Development Department, 1982.

Shawmount Newfoudland Ltd., Study of Small-Scale Hydro for Newfoundland and Labrador, Energy, Mines and Resources Canada, 1979.

Tung, T.P. and Barclay, J.C., Small-Scale and Low-Head Hydro Development in Canada: An Overview of Federal Activities and Policy, paper presented at Waterpower '85, September 24-27, 1985, Las Vegas, Nevada, Renewable Energy Division, Department of Energy, Mines and Resources.

Tung, T., An Overview of Small-Scale and Low-Head Hydro Activities from a Federal Perspectlve, Energy, Mines and Resources Canada, 1985.

MUNICIPAL EXPERIENCE

THE FANSHAWE DAM PROJECT

Doug Leitch
Upper Thames River Conservation Authority

INTRODUCTION

In 1946, the Ontario Government passed the Conservation Authorities Act, thereby setting up a vehicle for river basin management on a watershed by watershed basis. The prime mandate for Ontario's Conservation Authorities is the minimization of loss of life and property resulting from river and lake flooding. In fulfilling this directive, the Upper Thames River Conservation Authority has undertaken an exhaustive program of river channelization and dam and dyke construction. During the 1950's and 1960's, the U.T.R.C.A. constructed three major flood control reservoirs and several smaller water holding structures. The largest, and most important of these structures, Fanshawe Dam, has recently provided the Authority with an additional benefit - the production of hydroelectric power.

HISTORY

Fanshawe Dam was completed in 1952 on the North Thames River immediately upstream of the City of London. The main purpose of the reservoir was, and continues to be, flood control; however, over the years, an extensive recreational facility has developed in and around the reservoir.

Flows through the dam are controlled by 6 vertical lift sluicegates and two low-level discharge tubes. The headpond elevation remains at a generally static level throughout the year, and it is only during periods of high flows that the headpond elevation rises significantly.

Interest in power production has arisen several times during the 30-year history of the dam. However, for various reasons, it was never seriously pursued. Interest was again stimulated in 1982 when the Ministry of Natural Resources released a study detailing the potential of hydroelectric power production on existing dam sites in Southwestern Ontario. The study

concluded that Fanshawe Dam had one of the highest potentials for possible hydroelectric site development. Buoyed by the results, the Ministry of Natural Resources, in conjunction with the U.T.R.C.A., undertook a detailed feasibility study as an extension to their original inventory. The results of the study were positive, confirming that indeed, a feasible installation could be developed.

Coincident with the release of the background study, the Ministry of Energy announced their intention of making funding assistance available under the Canada/Ontario Conservation and Renewable Energy Demonstration Project for the development of small hydroelectric sites in the province. The favourable results of the feasibility study, combined with the possibility of funding assistance, were the catalysts required to convince the Authority to proceed. Indeed, the Ministry of Energy adopted Fanshawe as one of seven sites under the Enerdemo Program, and the planning and design began in earnest.

Immediately upon notification of our acceptance in the Enerdemo Program, a flurry of activity began. Engineering and design commenced July 1, 1983, and with commissioning completed July 13, 1984, the installation took approximately one full year to realize fruition. In that one-year span, the Authority had several enlightening discussions with provincial and local utilities, several levels of government, and finally, the financial community.

STATION DESCRIPTION

The feasibility study had identified several options with a unit of around 500 kilowatts considered as optimum. In order to reduce costly civil works, the method selected involved the removal of one of the existing low-level discharge valves and replacement with a 1.5 meter diameter penstock. The penstock directs the water up over the existing wingwall and down into the power house adjacent the downstream channel. Figure 1 indicates the configuration.

The prime mover is a Ossberger cross-flow turbine with horizontal admission limited by hydraulically-controlled guidevanes. The turbine is coupled directly to a Hansen gear-box which increases the rotation of the turbine to the synchronous speed of the generator. The motor is a 675 kw induction machine operating at 910 rpm and 4160 volts. The system is rated at 500 kw under full flow conditions of 6300 l/s and normal gross head of 11.2 m. The output of the machine may rise above 500 kw under heavy runoff conditions when the headpond in the reservoir rises significantly above normal. A schematic of the power house floor plan is shown in Figure 2.

A portion of the U.T.R.C.A. property is connected to the London P.U.C. grid, however, the Authority is actually a transfer customer of Ontario Hydro. The electric energy of the unit is

supplied directly by a short line, and power supplied to and from the grid is measured by reversible meters just downline from the station near the U.T.R.C.A. property boundary. The administration office and several smaller load sites, just upline of the Ontario Hydro metering equipment, are supplied from station generation. Surplus energy is then metered and fed into Ontario Hydro's grid. The system configuration is shown in Figure 3.

The feasibility study identified four potential users of the power generated. Those included:

1) The Upper Thames River Conservation Authority
2) London Public Utilities Commission
3) A private industry nearby
4) Ontario Hydro

Obviously, the highest return would be realized by using the power internally. In order to maximize this potential, the Authority entered into a unique wheeling arrangement with Ontario Hydro.

The U.T.R.C.A. operates three major remote load sites, all within an Ontario Hydro designated radius of 40 km of the station.

The utility allowed us to credit power generated at Fanshawe against consumption at these sites and for this privilege, the Authority agreed to a set charge of 0.7¢ per kilowatt-hour wheeled. This "wheeling" arrangement was in reality the deal which made the station viable. The U.T.R.C.A. would be replacing internal consumption typically costing 3.3¢ per kwh rather than receiving the then set rate of about 1.74¢ per kwh for excess generated. In addition, Ontario Hydro allowed the wheeling of kilowatts which were credited against energy demand at the remote sites. At the time, this wheeling arrangement was one of the first of its kind agreed upon for small hydro in the province.

As a further condition of the wheeling arrangement, the Authority was required to install central metering and purchase all Ontario Hydro distribution facilities at the load sites. The capital cost of this prerequisite was included in the final project cost.

The original feasibility study identified a total estimated capital cost of $800,000. Upon receipt of tenders and prior to construction, the cost estimate was revised to $840,000; the increase attributed to higher-than-anticipated costs for equipment, civil works and engineering.

The final cost of the station amounted to $848,000, some 6% higher than originally estimated. Of this total, the Ministry of Energy supplied a grant of $210,000 and the U.T.R.C.A.

financed the remaining $638,000 through its bank. Repayment schedules have been structured to account for general long-term increases in revenue and the payback period is expected to be about 10-12 years.

STATION OPERATION

The unit was placed in service on July 13, 1984. As with any new system, a series of bugs developed which initially proved distressing. Several of the problems which developed during the first year of operation were in some way connected to the control panel or wiring connections, while actual problems with the mechanical aspects were less frequent.

The first problem encountered was the plant's inability to meet anticipated power output. During the initial period of operation, the station's maximum power produced was approximately 80% of that which was anticipated. At the time, it appeared that the system had developed some major unaccounted head losses. In the period immediately following commissioning, the river was experiencing summer low flow discharges and the station was able to operate at significantly less-than-maximum discharge.

Approximately 1-1/2 months after start-up, heavy rainfall allowed the station to operate at maximum discharge for extended periods. During this time, power production increased significantly to approximately 95% of anticipated. Speculation was that some foreign material had become entrapped in the intake or penstock area and increased flows had washed it free.

The remaining loss of 5% was recouped in June 1985 when representatives of the turbine manufacturer readjusted the pressure relief intake on the runner casing.

The next problem arose about four months after initial start-up. The machine, because of its inductive nature, was drawing large amounts of reactive power from the grid. Ontario Hydro indicated they would begin charging for this unless we could increase power factor above 90%. However, the stipulation was that power factor correction must be such that the 0.9 criteria must be met at the Ontario Hydro meter, not the station itself. As previously noted, the Ontario Hydro meter is downline from the station and several minor load sites. We were effectively required to supply power factor correction to account for inductive loads from these sites as well. In order to achieve a 90% power factor at the station, 150 KVAR of capacitance was required; to achieve a 90% power factor at the Ontario Hydro meter, 300 KVAR of capacitance were required. The utility's reasoning was that they were charging for power into the system as read by their meter and the fact the station itself operated at 90% power factor was irrelevant.

Since the monthly reactive power charges resulting from this

decision amounted to some $1,200-1,500, the Authority had the power factor correction capacitance installed.

The most serious problem experienced with the station occurred shortly after the installation of the capacitor bank in mid-March 1985 and some 8 months after start-up. The generator experienced a stator coil failure resulting in a three-month station shutdown and a loss in revenue of almost $35,000. During the three-month timeframe, the generator was removed and the stator coil rewound at considerable cost. The cause of the failure has been investigated and remains a matter of concern to the Authority. The failure also disabled the capacitor bank which had been connected to the terminals of the generator.

Due to the severity of the breakdown, it was considered prudent to re-commission the station prior to start-up. The station was returned to service in June with no reactive power correction. This has led to severe reactive power charges of approximately 10% of our total monthly revenue. Some reconfiguration and re-design of the power factor correction system and delays in component deliveries have served to stall the re-installation of the capacitor bank until January of this year.

In addition to the problems listed previously, there were an abundance of minor "bugs" in the controls which led to numerous shutdowns during the first year of operations. These "growing pains" resulted in an average monthly downtime of 8% for the first year, exclusive of the March-June shutdown and routine maintenance periods.

The second year of operation has proven much more successful as unexpected downtime has dropped to virtually zero. Consistent with this pattern, the monthly operation and maintenance costs have decreased from approximately $1,000 to less than $500. This appears to be the minimum costs we can expect. Fortunately, this is about 40% below the amount originally anticipated.

One final problem relates to the streamflow frequency curve used for production estimates. The flow duration curve used in the power projections was based on a streamgauge measuring inflow into the reservoir. Unfortunately, the reservoir experiences huge evaporative losses and during extreme low flow periods, the curve adopted in the feasibility stage tends to over-estimate the actual available flow. To compound the problem, the curve selected considers total river flow availability at the turbine inlet. In order to meet this criterion, all flow equal to, or less than, maximum capacity, must be passed through the turbine. This can be accomplished only by closing the spillway gates which, in turn, results in more frequent headpond fluctuations and requires closer operator scrutiny.

POWER AND REVENUE GENERATION

The decision to proceed with station construction was based on an expected annual production output of 3.5 million kwh per year with anticipated revenues of $90,000 net in 1984 dollars. To date, the station's output has been slightly below these expectations. In the 1984 operational period, the total plant power production was 93% of that projected. However, this produced only 80% of the total anticipated revenue for the same time frame. During 1985, (exclusive of the three-month shutdown) the actual power produced was 99% of anticipated, with total revenues amounting to 94% of that expected. This tends to suggest that revenue expectations were slightly high, given projected power production levels, although balances between internal use and excess sales had some effect as well. It should, however, be borne in mind that these levels were attained with an average downtime of 8% in 1984 and 4% in 1985. On the other hand, average streamflows for the period of operations were 65% and 94% above normal for 1984 and 1985, respectively. Little emphasis should be placed on relationships between average yearly flows and power production as a linear relationship between the two does not exist. The data is presented merely to indicate that, to date, station production is representative of years for which streamflows were above average.

The total net revenue to the Authority from operational periods during 1984 and 1985 was approximately $34,000 and $81,000, respectively. The 1984 value represents approximately 5-1/2 months of operation and 1985 represents about 8-1/2 months of operation. The large difference in costs reflects the increased rates for parallel power generation effective January 1, 1985. Because of the significant rise in rates, increased revenues are expected to compensate for the less-than-anticipated output.

It is also interesting to note that had the station not suffered the major three-month shutdown in 1985, revenues would have amounted to approximately $116,000. Our projections were for $122,000.

As you are no doubt aware, Ontario Hydro offers a varying rate structure which rewards production outputs meeting set capacity factors. During 1985, the Fanshawe station was able to meet capacity factor requirements for all but the typical Thames River low flow months of February, June, July and August. Projections indicate that in normal years, September will also be included in this list.

SUMMARY

The Fanshawe small hydroelectric station is a 500 kw generator owned and operated by the Upper Thames River Conservation Authority.

It was placed into service in July 1984, approximately one year after a decision was made to construct the facility. During the 1-1/2 years of operation to the end of 1985, the station suffered several minor shutdowns, due in most part to faulty control wiring and equipment. There was one major three-month shutdown due to a burnt stator coil in the generator, resulting in a extremely costly repair.

Downtime during the first year of operation amounted to approximately 8% of operating time (exclusive of the major three-month shutdown). Over the following six months, downtime was reduced to virtually zero.

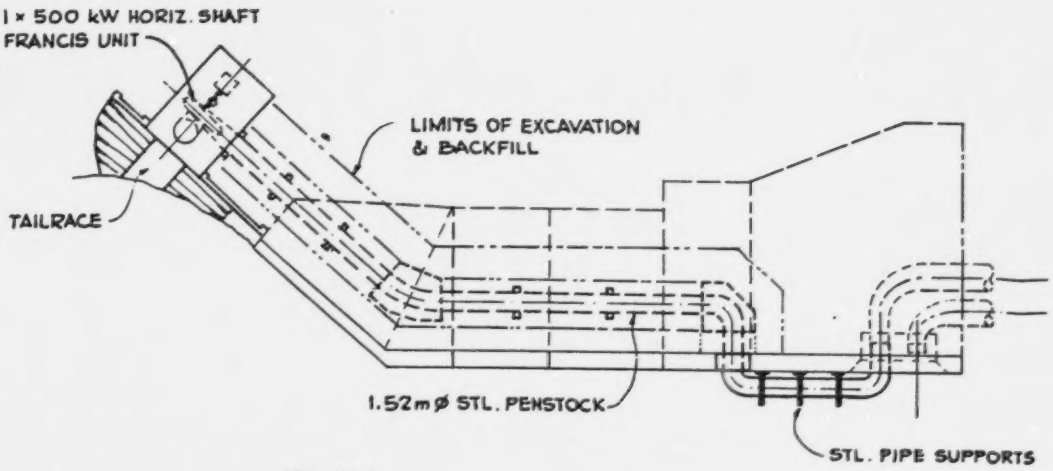
During this same 1-1/2 year period, power production was less than anticipated. In addition, the revenue associated with the power produced was slightly below expectations. The less-than-expected amount of power produced was partially caused by persistent shutdowns due to minor problems. On the other hand, river discharges were well above normal for the period. It is likely that the two will compensate for one another, producing close-to-expected power production during normal years. The less-than-anticipated revenues from the power produced are expected to be more than accounted for by increased rates for parallel generation.

After the first year of operation, the station's performance has proven much more satisfactory, with few unexpected shutdowns. If recent performance continues, it is anticipated that the original capital cost can be recouped in the expected 10- to 12-year payback period.

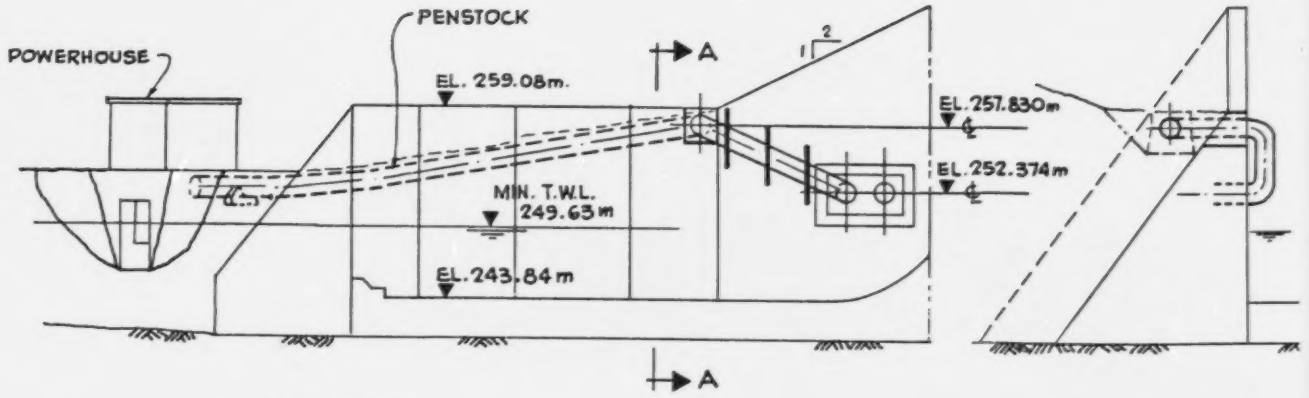
The first year's operation was a trying experience for the Authority, however, recent performance has been encouraging enough to prompt the Authority to conduct a feasibility study on another of its flood control reservoirs.

Douglas K. Leitch

- Graduated 1979 - University of Guelph with a B.Sc. (Eng.) degree in Water Resources Engineering
- Worked two years with private engineering consulting firm involved with projects in Hydrology and Hydraulics prior to joining Authority.
- Joined Upper Thames River Conservation Authority in 1981 as Project Engineer; assumed position of Water Management Supervisor in 1984, and is currently responsible for the overall operation of the Authority's Flood and Erosion Control program.
- Member of Association of Professional Engineers of Ontario.



PLAN

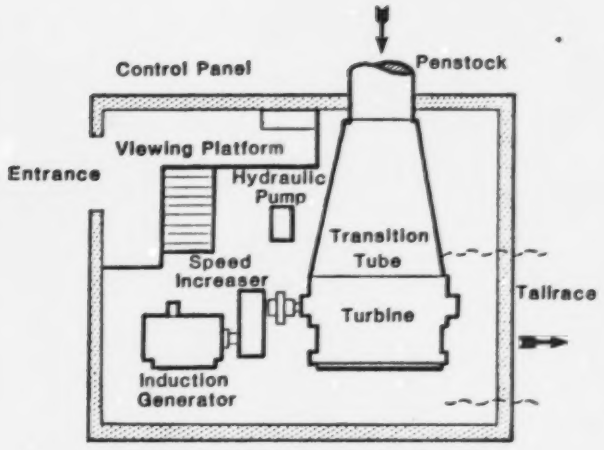


ELEVATION

SECTION A-A

fig. 1

FANSHAWE DAM
SMALL HYDROELECTRIC PROJECT

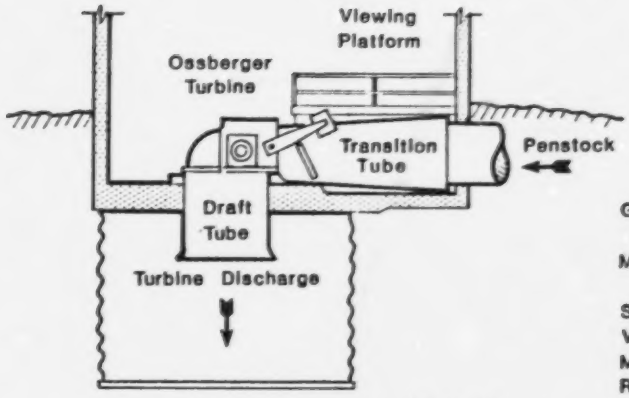


POWER HOUSE PLAN VIEW

ANNUAL POWER PRODUCTION
3.5 MILLION

TURBINE

TYPE – OSSBERGER CROSS FLOW
MANUFACTURER – F.W.E.
STAPENHORST INC.
NET HEAD – 11.3 m
MAX. FLOW – 8.3 cubic metres/s
SPEED – 141 rpm.



CROSS SECTION THROUGH
POWER HOUSE

GENERATOR

MANUFACTURER – RELIANCE
ELECTRIC
SPEED – 910 rpm.
VOLTAGE – 4160 v.
MAX. POWER OUTPUT – 875 Kw
RATED POWER OUTPUT – 500 Kw

fig. 2

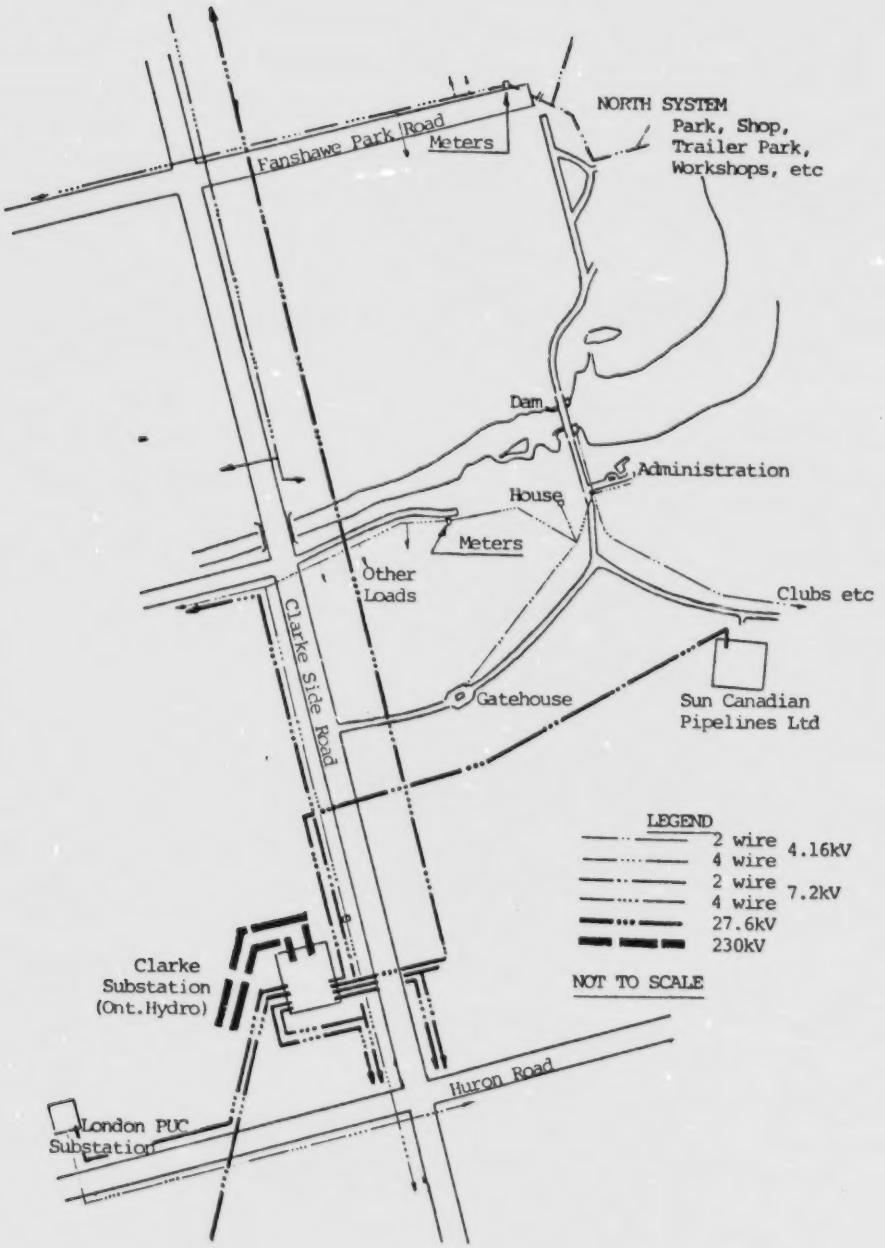

NORTH SYSTEM
Park, Shop,
Trailer Park,
Workshops, etc
Fanshawe Park Road
Meters
Dam
Administration
House
Meters
Other
Loads
Clubs etc
Clarke Side Road
Gatehouse
Sun Canadian
Pipelines Ltd
LEGEND
2 wire
4 wire
4.16kV
2 wire
4 wire
7.2kV
27.6kV
230kV
NOT TO SCALE
Clarke
Substation
(Ont.Hydro)
Huron Road
London PUC
Substation

fig.3

THE TRENTON DAM #1 PROJECT

Neil Robertson
Mayor
City of Trenton

The potential for low-head generation at Dam No. 1 on the Trent River in the City of Trenton was originally brought to the attention of the Trenton Public Utilities Commission in December 1982 by Mr. Bill Menzies, an employee of Ontario Hydro. Bill is directly involved in hydroelectric generation at two Ontario Hydro Generation Sites above No. 1 Dam on the Trent River System.

Mr. Menzies' proposal was to utilize part of an old installation which supplied power to the British Chemical Company back in the early 1900's. Perhaps it would be of interest to you that the British Chemical Company employed over 3,000 men in Trenton, producing explosives which provided the ammunition for the troops in the Great War. It operated daily around the clock since it began production for over a year-and-a-half until the Thanksgiving Weekend of October 12 - 14, 1918. The war which had dragged on for four years was coming to its conclusion. It was probably a coincidence, but it was decided that the plant be shut down for a holiday on Thanksgiving Weekend and mysteriously enough, with virtually all the employees away, the Chemical Plant caught fire and blew up within hours, destroying almost all of the 204 buildings on the site.

We were fortunate the entire town didn't go up with the plant but, on the other hand, what do you do with a T.N.T. factory and no war to produce explosives for? Parts of the old Chemical Plant are still visible on the west bank of the Trent River today.

I would like to give you a little historical background on the site and "wave the flag" a little for my city, Trenton. In 1885, Trenton pioneered in the development of electric power as a municipal enterprise. In that year, application was made to the Ontario Legislature for permission to construct dams on the Trent River for the conversion of water power to electric energy. An Act was passed by the Legislature authorizing the town to erect a dam. No other municipality had received such permission.

Records indicate that in September 1892, a proposal was presented by the Bush Electric Lighting Company to illuminate the town for a period of ten years - there would be a total of 24 lights which would burn all night at a cost of $1,440.00 per year.

In August 1895, the Trenton Light, Heat and Power Company, with a capital of $50,000, applied to the Ontario Government for a Charter; the objects of the Corporation being for the purpose of "supplying electrical light, heat and power to the Town of Trenton". The following month, the Council of the Town of Trenton awarded a contract to Bush Electric Company of Cleveland for lighting the town for a period of ten years.

A newspaper announcement of this award states, "The Company will have at their disposal, one of the finest water powers in the Dominion. The generator would be capable of producing 12,000 H.P." The news article continues, "The William Hamilton Manufacturing Company and the Canadian General Electric Company received the contracts for the water power and electrical plant, respectively, for the first three-phase electrical plant erected in Canada. These contracts involve an outlay of $50,000 and it is proposed to run electrical wires to Belleville, twelve miles distant, for the transmission of electricity for light and power."

A news item of July 1896 informs us that the new power house of the Trenton Electric Company at Trenton was operational with a regular service supplied to the town. Also, the line to Belleville, twelve miles distant, was completed. The first motor used in Belleville was a 35 KW synchronous Canadian General Electric standard type from which power was supplied to operate the arc machines.

It goes on to state, "The Trenton building is a large and substantial one, erected on the Trent River a short distance east of the Grand Trunk Railway Station. The roof and sides are covered with iron sheets. The waterwheel consists of two 150 H.P. vertical turbines, manufactured by the Williams Hamilton Company of Peterborough. They are geared directly to a large 6-inch line-shaft which runs the whole length of the building. A convenient arrangement is made by providing each of these wheels with a friction clutch whereby each may be used independently of the other. The two large generators are 200 H.P. each bolted direct to two pulleys on the line shaft, eight feet in diameter.

The switchboard, measuring 7-1/2' x 6', consists of three panels of white marble on which are mounted, at various instances, switches, regulators, etc. necessary to the control of such a large plant."

Sadly, there is no information available regarding the demise of this original structure. We do know that the present dam

was completed in February 1915. It is currently owned and operated by Parks Canada to control water levels in the Trent Canal System. This present structure is of reinforced concrete, having 18 spillway bays each of which are 25 feet in width, equipped with 10 x 14 inch timber stop logs.

The downstream half of the dam originally supported a railroad trestle, but this has now been removed.

After discussing the Menzies' proposal early in 1983, our Commission engaged Shawinigan Lavalin, a consulting firm, to conduct a preliminary study to ascertain the viability of the project. For study purposes, it was decided our model would be a relatively simple installation which would utilize two of the dam spillways. Two verticle shaft pump turbines would be installed in each spillway. The downstream wingwalls would be sealed, the areas de-watered, concrete footings poured and the units set in place. Each of the four units using induction generators would be capable of producing 240 KW at 1200 R.P.M. and would deliver the power at 4160 Volts into the Trenton P.U.C. distribution system approximately 300 yards from the site.

The $2,400 preliminary study completed by Shawinigan proved the project to be technically sound and financially viable.

The Trenton Commission approached the Ministry of Energy with our proposal and the positive results of our preliminary study. The Ministry agreed to fund ninety percent of an in-depth study and we again engaged Shawinigan at a fee of $38,000 to carry out an in-depth feasibility study satisfactory to the requirements of the Ministry of Energy.

It was decided that this full study would be based on utilizing three spillway bays and six 200 KW submersible turbine generators. The change of equipment from our original study model of four pump turbines was the recommendation of our consultants in order that we obtain the optimum amount of power from the water flows available.

The River water flow duration curve indicated that these six units would have sufficient water to operate 74% of the time. Once again, this study proved the proposed project to be technically feasible and financially viable.

The estimated annual energy output from the plant will be 9.5 Billion Watt Hours. The payback period, if financed at 14%, will be thirteen years. To quote Shawinigan, "It is recommended that the Commission enter into negotiations to obtain the approvals of Ontario Hydro, Parks Canada and other Government agencies and arrange financing necessary to enable the Trenton P.U.C. to execute the project."

Since the Trent River is part of the Heritage Trent/Severn

Canal System, the waterways fall under the jurisdiction of the Federal Government and thus, within the jurisdiction of Parks Canada. We, therefore, must satisfy many of the concerns which Parks Canada has, since the prime use of this canal system is recreational boating and it is necessary that water levels be maintained at a depth and rate of flow conducive to the operation of the locks.

It is also important that physical changes to the dam structure or the equipment installed do not inhibit Parks Canada's ability to remove logs and react to possible flood conditions on the River.

A white paper has now been developed by Parks Canada which outlines the potential problem areas that must be addressed by any small hydro developer. The paper specifies certain facilities which must be installed to meet their concerns, such as heated gains, lighting, trash racks, etc. These criteria are to ensure against additional workload for their staff and their concern for the aesthetics of the dam and the surrounding area. Since the site is determined as a Heritage Canal, it is most important that any alterations or additions to the structure or the site not detract from the existing conditions.

The financial implications for a small municipality endeavouring to carry out a project of this magnitude (estimated at 3 million dollars) are much different from what would be faced by private industry; it is most important from the standpoint of the politician that the ratepayers of our city not be subjected to any penalty as a result of undertaking the development. Therefore, the financing of the project is crucial. The payment schedules must be such that the energy produced and thus, not purchased from Ontario Hydro, will offset the interest charges and the principal cost, as well as the ongoing maintenance of the facility.

With the aid of Ontario Hydro staff utilizing their computer expertise, many financial scenarios have been produced. In any analysis, assessment of the probable Ontario Hydro charge for power over the next twenty years is paramount. Also of importance in our analysis is the probable fluctuation of interest rates and the determination as to whether or not any upfront capital should be injected into the project.

To evaluate the financial aspect of our project, the Ministry of Energy has made available to our Commission, ninety percent of the cost to a maximum of Ten Thousand Dollars to undertake a financial assessment of some financing scenarios.

These models are as follows:

1. CONVENTIONAL MUNICIPAL DEBENTURING

This form of financing would lock the Utility into a standard annual repayment premised on existing interest rates at the

time of issuance of the debenture. The drawback of debenturing is, should the cost of power escalate over the twenty-year period, the scheduling could not be changed even though additional funds would be available to more rapidly repay the debt. Debenturing also places restraints on the city - it would reduce the amount that the Ontario Municipal Board would approve to permit the city to carry out some other capital projects that must be debentured.

2. LEASE FINANCING

The advantage of lease financing over conventional debenturing is the periods of time can be flexible and the Commission could re-evaluate its financial requirement in a shorter time frame. Under lease financing, the Class 34 Tax Incentive cannot be utilized. This tax incentive enables a private developer to write off up to fifty percent of the equipment cost over a three-year period.

3. TURNKEY: SHORT-TERM BUYOUT

There are advantages and disadvantages to this scheme. An advantage would be "no risk" in the commissioning of the plant and working out the "bugs" that must be overcome in the initial startup. Another advantage is it would give incentive to private developers to utilize the Class 34 Tax Incentive.

The disadvantage to our Commission is the developer will build into his buyout price, the risk he must take in commissioning and debugging the plant.

4. TURNKEY: LONG-TERM BUYOUT

This has the same benefits and risks of the short-term buyout. An additional disadvantage to the Commission is the developer will ensure that he is totally protected over a longer period of time from all eventualities such as the cost of money and fluctuations in the cost of power.

5. ENERGY SERVICE COMPANY

From the standpoint of the Commission, this is the safest financial arrangement to enter into. This would mean that the private developer would sell power to the Commission at a rate below that of Ontario Hydro, thus ensuring an immediate savings to the Commission and no capital cost.

In the last three options, it is most important the Commission establish the terms for the purchase of the power. When we purchase power from Ontario Hydro, the monthly invoice consists of two components' peak demand and K.W.H. consumption.

The peak demand charge makes up more than fifty percent of the

cost to us and is determined by the highest demand over a one-hour period during any day of each month. Therefore, it must be clearly established that we will pay for power from the developer on the basis of the K.W. supplied to us at this peak demand period.

At this time, the Trenton Public Utilities Commission is in the process of having these five scenarios for financing assessed by a consultant. We are also, with the aid of the Ministry of Energy, having some additional concerns of Parks Canada assessed and analyzed by Shawinigan Lavalin.

Further information is required on:

- The alternatives for spilling water flow in the event of unit shutdown.

- Inter-operation with respect to water levels, gate operations, heating gates, heating stoplog guides, operation and maintenance requirements.

- Re-evaluation of energy output and benefits with respect to changes in energy prices during winter operations.

- Revised capital cost estimates to include gate heaters, stoplog guide heaters, the escalation of equipment costs and construction prices.

- Revised economic analysis to take account of changes in energy output, energy prices and capital cost estimates.

- And we must prepare an environmental statement for submission to Parks Canada.

Upon completion of these two final studies, hopefully we will be in a position to proceed and, God willing, the City of Trenton will once again be utilizing the latent energy of the Trent River to produce electricity after a hiatus of seventy-five years.

Neil Robertson is Mayor of Trenton.

THE WEMINDJI SMALL HYDRO PROJECT

John Lemieux and Walter Hughboy
Wemindji Band Council

Wemindji Band
Wemindji, James Bay
(Quebec)

INTRODUCTION

In January 1985, the Wemindji Band commissioned a 1.1MW mini-hydroelectric plant on the Maquatua River in Northern Quebec. The event was a milestone in the ongoing efforts of the Wemindji Band Council to provide a reliable source of basic electricity to the 900 residents of the Wemindji community.

To the best of our knowledge, the Wemindji Band is the first remote Indian band to have, on its own initiative, undertaken the planning, construction and operation of a small hydro development of this size in Canada. While the technology involved might not have been new, the socio-political problems related to the undertaking were, and to the extent that they may be transferred to other Indian bands or even remote municipalities planning the same type of undertaking, we are pleased to have this opportunity to review that experience with you today. We thank the Ontario Mimistry of Energy for extending us this invitation.

The Wemindji Band is now, by virtue of recent federal legislation, technically a municipality. At the time of the decision to construct, however, the Band was essentially an Indian Act band with limited local government powers and was financially reliant for deficit funding upon Indian and Northern Affairs Canada (DIAND). As such, while the Wemindji Band had effective tax-exempt status, it did not have the usual access to capital and preferred borrowing rates which result from provincial government guarantees on debt funding requirements. The Band's experience proved to be more akin to that of a private rather than municipal developer.

WEMINDJI BAND HISTORY

We think it is useful to provide a little more than the usual background with respect to the Wemindji Band and the Maquatua

Mini-Hydro Project. The situation prevailing for the Wemindji Band prior to the project was not atypical to that faced by other remote native communities and underscores the extent of the disparities which continue to exist between northern and southern, native and non-native communities.

The Wemindji community is located on the eastern shore of James Bay, 1,200 km north of Montreal and is one of eight Cree Bands which traditionally hunted, fished and trapped along the coast and over vast areas of traplines between the 49th and 55th parallels in Northern Quebec.

Shortly after the turn of this century, the Wemindji Crees came to spend their summers on the James Bay coast near what was then a Hudson Bay Company trading post known as Old Factory. The Band was later registered as the Old Factory Band under the Indian Act and in the 1950's relocated thirty miles further north along the James Bay coast to its present site, then called Paint Hills, recently renamed Wemindji, following the signing of the James Bay and Northern Quebec Agreement in 1975.

THE JAMES BAY AND NORTHERN QUEBEC AGREEMENT

Quebec's James Bay Project had the effect of propelling the eight Cree bands into an era of modern development. Prior to that, they had been largely neglected outposts in the far-flung maze of some 540 Indian bands administered by Indian and Northern Affairs Canada.

Cree and Inuit opposition to the James Bay Project led to the signing of the first modern land claims settlement treaty, the James Bay and Northern Quebec Agreement. The Wemindji Band, with the other Cree Bands of Quebec, signed that agreement with the governments of Quebec and Canada and other parties, including Hydro-Quebec.

ENERGY SUPPLY IN WEMINDJI HISTORICALLY

A generation ago, the Wemindji Band was in the dark ages in terms of electricity supply. At that time, Indian and Northern Affairs began furnishing diesel-generated electricity to the schools they operated in local Indian communities. Prior to that, supply was through a limited number of individually-owned generators and, for all intents and purposes, community residents went without electricity.

From that beginning, Indian and Northern Affairs stumbled into the business of energy supply, at least in Northern Quebec communities, as local distribution systems were first extended to other Indian Affairs installations and then to residential housing.

By 1975, the Wemindji community found itself with a small but rapidly-expanding population, with new and modernized

facilities and an increasing energy demand. It was also in a constant pattern of brown-out or black-out as DIAND-operated diesel generators broke down or were unable to meet demand. While electricity was furnished to Indian residents free of charge, (non-natives were charged $0.33/Kwh), Indian Affairs' costs dramatically rose as prices and population increased. Delivered cost of a kWh in Wemindji was in excess of $0.50 by 1983 and total operating costs were on the order of $1 million. The overall net effect was that an ever increasing proportion of Indian Affairs' Quebec Region budget was being absorbed to meet electricity costs with consequent cut-backs in other services provided to the Crees by that Department.

DIAND facilities prior to the mini-dam provided electricity from a diesel power station with an associated tank farm. Three generators, two rated at 300 kW, 375 kVA, 1,200 RPM and one 850 kW located in a trailor. One of the 300 kW generators was designated as stand-by so that the total nominal capacity was 1,150 kW. The community was supplied with diesel oil transported by barge from Moosenee, Ontario, at the southern end of James Bay.

It is one of the ironies of the James Bay and Northern Quebec Agreement that while it facilitated the construction of 5 major transmission lines to carry power south, it did not provide for the immediate construction of connector lines to all of the James Bay Cree Indian communities.

The James Bay and Northern Quebec Agreement had provided for the accelerated implementation of an earlier Protocol Agreement between Canada, Quebec and Hydro-Quebec. Under that arrangement, Hydro-Quebec was obligated to take over DIAND's facilities in native communities in Northern Quebec, on the condition that DIAND first upgrade its existing installations to Hydro-Quebec standards. The Protocol Agreement was simply not being implemented, much less accelerated, with the result that Wemindji, along with two other Cree coastal communities, was never linked to the main Hydro-Quebec grid system.

THE SAKAMI LAKE AGREEMENT - THE IMPETUS FOR THE MINI-HYDRO PROJECT

In 1979, the Wemindji Band entered into an agreement with Hydro-Quebec and its subsidiary, the James Bay Energy Corporation, under which the Band was to receive gradual control of approximately $25 million in return for its consent to modifications to the larger James Bay Project sought by the two corporations and to offset the negative impacts of those modifications.

The Sakami Lake Agreement effectively paved the way for the Wemindji Band to take control of its own destiny in terms of energy supply and, ultimately, to build the Maquatua River Mini-Hydro Project.

This Agreement contemplated the supply of electrical power to the community through the construction of a transmission line from the community to the proposed La Grande I dam site. While the transmission line solution was the one preferred by Hydro-Quebec and the James Bay Energy Corportion, the Sakami Lake Agreement did not oblige the Band to proceed with that solution. The Band thought that studies would prove that other alternatives might be better.

In the face of increasing concern with the inadequacy and unreliability of the DIAND-operated diesel generators, the Wemindji Band, acting through a Band-controlled corporation, the Sakami Eeyou Corporation (formed to hold and administer the Sakami Lake Agreement funds), actively pursued three alternatives:

- a 120kV transmission line linking Wemindji to the Hydro-Quebec main grid at the La Grande 1 dam sub-station, some 82 km distant;

- upgrading of the existing Indian Affairs' diesel generator system;

- development of a mini-hydro plant on the Maquatua River which ran through Band lands approximately 1 km from the village and into James Bay.

PRE-FEASIBILITY AND FEASIBILITY STAGES

The Wemindji Band commissioned a series of economic and technical studies on the options available to provide electrical energy to the community.

An initial analysis of alternative energy sources for the community of Wemindji was carried out in 1980 by a research group from the University of Waterloo. Four possible sources of power generation were examined:

(i) existing diesel fuel units;

(ii) biomass combustion and wood stoves;

(iii) a biomass gasification system; and

(iv) hydroelectric potential from the Maquatua River flowing into James Bay.

These energy sources were analyzed in various combinations over a ten- and fifty-year period. Early indications indicated that the most cost-effective system was the development of the hydroelectric potential of the Maquatua River with residential heating energy coming from wood stoves and the existing Indian Affairs diesel fuel generators used as a back-up system.

The Wemindji Band now believed that it was on the road to a viable long-term solution to its energy problems. Again, acting through the Sakami Eeyou Corporation, it commissioned a series of detailed comparative, technical and economic evaluations of the implications of mini-hydro development, the use of diesel fuel generators and the construction of a transmission line. This work was carried out by the SNC Group of Montreal and the first "Pre-feasibility Study of the Maquatua Power Project, September 1981", found that of the 3 options available, the mini-hydro offered a significant advantage over thermal generation in reliability, equipment life and fuel requirement, particularly, given that dependence on diesel generation required fuel that was becoming increasingly expensive.

Four major sites along the Maquatua River were considered:

Three run-of-the-river sites identified as M-1 (km 1.3), M-3 (km 3) and M-9 (km 3) and a storage reservoir site, M-71 (km 71). While the storage reservoir site had the advantage of providing storage for summer run-off to be released to power sites downstream during winter, the benefits of regulation were outweighed by the cost of site and access road construction. This report concluded that:

(i) Though the development of the M-1 site on the Maquatua River would not be adequate in the long-term to fully supply the total projected energy requirements of Wemindji, it offered an economical first-phase solution to the basic electrical needs of the community, with the peak primary heating coming from wood fuel and/or oil;

(ii) The optimal location for an initial mini-hydro development was, in fact, at site M-1; and

(iii) The mini-hydro plant had further advantages in making maximum use of the local labour during construction, operation and maintenance.

Based on the foregoing results, the Wemindji Band commissioned a more detailed energy study, again carried out by the SNC Group in September 1982.

The "SNC Wemindji Energy Study" projected population growth and community expansion over a fifty-year period in the context of the three main alternatives: diesel generation, transmission line and mini-hydro plant, and furthermore, considered the issue of energy supply for heating which was considered in relation to the use of:

(i) wood-fired stoves or furnaces;

(ii) oil furnaces;

(iii) electrical heating from the Hydro-Quebec grid and;

(iv) electrical heating supplied by surplus energy from a mini-hydro plant.

The Wemindji Energy Study concluded that an initial mini-hydro installation at site M-1 with an installed capacity of 750 kW (subsequently optimized to 1.1 MW) would supply current basic needs, 95% of the institutional and commercial heating requirements and approximately 40% of the residential heating requirements for the Wemindji community. More importantly, the study found it would satisfy the basic electrical needs for up to thirty years. Further site investigation in December 1982 confirmed the suitability of the M-1 site.

ENVIRONMENTAL SETTING

The Maquatua River is about 120 km long. The head waters drain an area south-west of the La Grande II reservoir and west of Sakami Lake, including Bruce Lake and Lake Yasinski. The River flows into the east side of James Bay at the community of Wemindji. The total drainage basin is 1,081 km^2 at Wemindji and 1,040 km^2 at site M-1. The annual hydrograph for the River shows a seasonal pattern typical of other northern Canadian rivers, with the spring flood from May to June, average flows through the summer and a slight flood in the autumn followed by low winter flows.

Numerous falls and rapids are present in the stretch of Maquatua River between Bruce Lake (70 km from James Bay) and Wemindji. At the onset of winter in November, these rapids produce a large amount of frazil which is carried down to the estuary in front of Wemindji. In December, the extent of ice cover on the River progresses at a fast rate, thus reducing the potential frazil-generating areas. In the middle of winter, the open water stretches are reduced to the steeper portions of the main rapids. Ice break-up occurs normally in April.

The physical environment was found not to pose any significant obstacles to the construction of the project.

SOCIO-ECONOMIC PROFILE OF WEMINDJI

At the time of project decision, the community was comprised of about 100 homes surrounded by the usual range of public and commercial buildings in remote communities, including a Band office, school, nursing station, Anglican church, a co-op general store and a Hudson's Bay store. The community though was undergoing a period of rapid expansion as a result of initiatives by the Band Council but also as a result of larger initiatives undertaken by the James Bay Crees and their housing authority, the Cree Housing Corporation. A community master plan had provided for the refurbishing and improvement of existing housing, residential expansion with new house

construction in the village, improvement of community facilities, including a new church and hockey arena and development of basic infrastructure so as to provide a water and sewer system to all houses. Moreover, the airstrip north-west of the community was to be extended and upgraded by Transport Canada to permit expanded and more reliable air service by Air Creebec, another James Bay Cree-owned company, and other small airline operators. Recent or planned investment other than the mini-hydro was in the range of $25 million.

Access to the community, however, was and is limited to barge traffic in summer, year-around access by air for limited-size aircraft and occasional access by 100km of costly winter road built only when justified by other community projects.

Of the approximately 100 households (then with an average of 6.3 persons per household), the majority still depended on the traditional subsistence economy for their sources of food. More than half of the Wemindji Band members were trappers who spent much of their winter trapping on their inland traplines. After spending the winter in the bush, the trappers returned to the community in the spring. Most residents did and continue to participate in both the spring and fall goose hunts along the coast and, in the summer months, fishing is an ongoing activity along the James Bay coast and on inland rivers and lakes.

It was anticipated that, in the future, traditional bush food harvesting activities would continue to be of central importance to the Wemindji community. With an expected decrease in the temporarily high rate of employment on construction activities, it became evident that there would be a need for long-term study of employment opportunities compatible with community skills and aspirations - which opportunities could in no way be guaranteed.

The environmental assessment carried out by the Band with respect to the project showed that after taking into account all known sources and adjusting payments received from a special trapper's income security program, the average family income for Wemindji was about $10,000, with average family size of 3.75 members. The income figure was well below the "poverty line" figure estimated by Statistics Canada which, for a family of four, was then in the range of $13,000 - $16,000 annually.

This factor was one of the significant socio-economic reasons for opting for the mini-hydro solution. Quite apart from other factors dictating choice of the Mini-Hydro alternative, there was, quite simply, little or no available income to pay for the electricity bills which would have resulted from a Hydro-Quebec transmission line. The community did not have the cash economy to support such energy bills. The Band Council also had a point of comparison with another Indian Band, the Chisasibi

Cree Band, located 150 km up the coast. That Band, after linking-up to the main hydro grid for basic and heating requirements, found electricity bills put an unsupportable strain on the local economy.

FINAL PROJECT DESCRIPTION

The Maquatua Mini-Hydro Plant, the solution ultimately retained by the Wemindji Band, involved the construction of a run-of-river mini-hydro electric plant with a 1MW S-type horizontal turbo generator located at site M-1 on the Maquatua River about 1 km from the center of Wemindji.

The installation consists of a concrete - gravity overflow dam with maximum height of approximately 11.5 meters and a powerhouse with the turbo generator unit. The concrete dam acts as a spillway and the installation includes a diversion channel to supply the powerhouse, which is located in the middle of the channel. A rockfill dike is located in a valley just to the south of the dam. The forebay reservoir pool is approximately 2 km long and of sufficient capacity to be able to meet peak daily demand for electricity until 2008. The power plant is connected to the existing electrical distribution system which was significantly upgraded and adapted to serve long-term needs and the then-existing Indian Affairs' 850 kW diesel generator is utilized as stand-by and for future peaking demands.

ROLE OF JAMES BAY ENERGY CORPORATION

Almost from the beginning of its investigations, the Wemindji Band had the benefit of a special association with the James Bay Energy Corporation, the Hydro-Quebec subsidiary which had played a key role in the construction of the James Bay (La Grande Complex) Project and which continued to play an important advisory, if somewhat diminished, role in the post-construction phase of activities in the James Bay territory.

The Sakami Lake Agreement had provided a place on the Band-controlled board of directors of the Sakami Eeyou Corporation for a representative of the James Bay Energy Corporation. Throughout the pre-feasibility and feasibility stages of the Band's investigations, the James Bay Energy Corporation, through its board representative, funded, supported and, in some cases, supervised the Band's initiative. The Corporation's assistance gave important recognition and acceptance of the Band's right to determine the solution to a local issue, notwithstanding Hydro-Quebec's obvious interest in the choice of the alternative transmission line solution.

SOCIO-ECONOMIC AND ENVIRONMENTAL ASSESSMENT

By January 1983, the Wemindji Band had decided to proceed with the construction of the plant and submitted a detailed Socio-Economic and Environmental Assessment Statement, together with a request for authorization to build, to the appropriate environmental authority.

In the circumstances, because the project was located wholly within the perimeters of Band-controlled lands (Category IA), the project was subject to the environmental regime created under the James Bay and Northern Quebec Agreement and special Quebec implementing legislation. More significantly, project authorization, for environmental purposes, was within the jurisdiction of a local environmental administrator. The Impact Statement, which incorporated the results of consultations not only with the members of the Wemindji Band but also with Indian and Northern Affairs, various Cree umbrella agencies operating in the territory, and the James Bay Energy Corporation, attempted as wide a perspective as possible on the socio-economic implications of the project for the community.

In April 1983, environmental authorization was granted by the local administrator in Wemindji, which satisfied all of the legal requirements in this regard. The authorization was subject to standard terms and conditions and included a number of recommendations regarding future energy allocation policies for the community and the pursuance of hydrological studies on the Maquatua River with a view to optimizing the operation of the project.

Worth noting, the provisions of the Quebec Environment Quality Act implementing the environmental regime in the James Bay and Northern Quebec Agreement confirm the delegation of power from the Quebec Deputy Minister of the Environment Department to local Cree band-appointed administrators in the case of the assessment and authorization of projects located on Category IA lands. In retrospect, the location of this project wholly within the boundaries of those lands and the effective containment of environmental assessment to local factors was not only a fortuitous event but an important factor considered in the various choices within the mini-hydro option itself.

BAND DECISION TO BUILD ON INTERIM SELF-FINANCING BASIS

In March 1983, the Wemindji Band was ready to proceed with the project. Major equipment tenders were in and within planning estimates and a target-price contract for the main construction phases had been negotiated. (Contracts were subsequently awarded to Dominion Bridge-Sulzer Inc. for the turbo generator and Armco for the water intake gate. The Wemindji Band again tied-in to the larger Cree network operating in the James Bay Territory with respect to the main construction contract. This

contract was eventually awarded to the Cree Construction Company (Quebec) Limited, a wholly-owned Cree company which had acquired considerable experience in the region since the signing of the James Bay Agreement in 1975 in the execution of housing and infrastructure projects.)

Indian and Northern Affairs were not ready to participate. Both preceding and during the years covering the pre-feasibility and feasibility studies, the Band had been involved in ongoing discussions with Indian and Northern Affairs to convince the latter, both as to the economic and technical viability of the mini-dam and, more importantly, that the Department should play a direct participatory role with the Band in all phases of the planning, execution and funding of the project. While Indian and Northern Affairs had made a small financial contribution to the cost of the preliminary studies, the Department did not have the technical capacity to assess the Band's project and was locked-in to capital funding formulae which were incapable of dealing with funding requirements of the magnitude called for by the project. In the result, Indian and Northern Affairs consideration of the project, emanating both from Headquarters and the Quebec Region offices, hardened from scepticism and delay to opposition, despite the project's obvious technical and economic merit. The Band maintained that Indian and Northern Affairs had a long-standing legal and trust responsibility to provide adequate electricity in the Wemindji community, which it was not able to deliver with its existing plant and, moreover, that it had undertaken a more specific obligation to accelerate the above mentioned Protocole d'Entente Agreement in the Wemindji community.

At that point in time, the Band was in a position to take advantage of lower construction costs insofar as the Cree Construction Company (Quebec) Limited had already mobilized in Wemindji in connection with other ongoing projects. The Band was also in a position to cap estimated project costs at $6.5 million. It was faced with the huge uncertainty of cost-reimbursement from any government source. The Wemindji Band decided to accept the risk and the decision was made to proceed with the project without Indian and Northern Affairs' active participation.

LEGAL ASPECTS - UNIQUE POSITION OF THE WEMINDJI BAND

At the same time, a detailed application for project funding was submitted to the then Minister of Indian Affairs and Northern Development in March of 1983.

The decision to build in the absence of secured government financing was made by the Band with full knowledge of the risks involved and has, in retrospect, proven to be the most difficult obstacle to overcome.

As noted above, the Mini-Hydro Project was located within lands transferred under the terms of the James Bay and Northern Quebec Agreement by Quebec to Canada but for the exclusive use and benefit of the Band to use as if it were the owner thereof. More particularly, the project lands were within an area of Band lands known as Category IA, which are subject to federal rather than provincial jurisdiction. The Band, on the advice of legal counsel, maintained the position that it has the requisite authority to itself use the land, water and other resources required for the project, a position with which provincial authorities have not chosen to disagree, though given the opportunity to do so. The Band, moreover, took the position that the Maquatua River was not a navigable river.

During the course of construction of the project, the Wemindji Band's status as a local government was confirmed. In June, 1984, federal Parliament adopted special self-government legislation, the Cree-Naskapi (of Quebec) Act which conferred local government status and powers on nine Indian Bands, including the Wemindji Band, again, pursuant to the provisions of the James Bay and Northern Quebec Agreement. Prior to the adoption of that legislation, the Wemindji Band was in a transitional stage where its powers were, if not unclear, then unrecognized to their full extent.

Significantly, under the new legislation, the Wemindji Band also became empowered to enact by-laws respecting the establishment, maintenance and operation of energy services and respecting user charges for such services. The legislation paved the way for the Wemindji Band to assume legal control and responsibility for the provision of electricity to the Wemindji community on terms and conditions it insisted on negotiating with Indian and Northern Affairs.

PARTICIPATION OF THE FEDERAL GOVERNMENT

The Role of Energy, Mines & Resources Canada

The Wemindji Band had, from the outset, enlisted the assistance of a number of different federal departments, including Energy, Mines & Resources Canada. The Band sought the financial support of EMR through the application of available programs and, equally, the political support of EMR, given the ambivalent position taken towards the project by Indian and Northern Affairs. In what amounted to a bold decision, EMR ignored the debate between the Band and Indian and Northern Affairs and, after making its own assessment of project viability and merit versus other alternatives, declared the project eligible for funding out of its Conservation and Renewable Energy Demonstration Program (ENERDEMO) and entered into a contribution agreement to fund up to $659,000 of the eligitle costs of the $6.5 million project.

Additionally, EMR agreed to contribute to the costs of an

evaluation of energy mangement systems in remote communities. The Study, funded partly through the Remote Community Demonstration Program (RCDP), reviewed the available options to minimize actual consumption of energy and optimize the use of all sources of energy available to the Wemindji community. The results will be used in the Band's implementation of a comprehensive energy management strategy for the future. The study also emphasized training of local personnel required for operation and maintenance of a combined mini-hydro and diesel system, the use of energy audits and other management techniques. The Wemindji community was considered a suitable location and an ideal opportunity to assess an actual project and transfer the results to remote areas elsewhere within and without Canada.

Canada Employment and Immigration Commission

The Wemindji Band applied for, and received assistance, under two CEIC programs. Under the Industrial Training Program, Canada Manpower contributed to the funding of an intense operator training program carried out at the Wemindji site and at Ontario Hydro facilities at Orangeville, Ontario. Under a separate Career Access program, the Commission contributed toward the funding requirements of an on-the-job training program extending for fifty-two weeks.

Indian and Northern Affairs

In contrast to the above-mentioned assistance, Indian and Northern Affairs represented a major obstacle to project realization. From the Band's perspective, Departmental representatives were unable to conceive of the Band successfully undertaking a project of such magnitude and were, as a result, determined to distance themselves as far as possible from the project. The more determined the Band became to proceed with the project, the more fixed the Department became in its opposition. The Department raised several arguments against the project and to justify its non-participation, including:

(i) The Department's objectives in Wemindji were not necessarily identical with those of the Band, although the former were never clearly identified;

(ii) the Mini-Hydro Project was not the best economic solution of the alternatives studies, notwithstanding the assessment of Energy, Mines & Resources Canada otherwise in this connection;

(iii) the project was not ultimately cost-effective because it did not present a permanent solution.

In fact, the advent of the Mini-Hydro Project served to underscore the inherent weakness of Indian and Northern

Affairs' energy policy in Northern Quebec communities. The Department is, in effect, locked-in to a funding scenario under which it has been unable to plan capital investments that provide a long-term solution. Instead, DIAND budgets for increasingly onerous operating expenses. In Wemindji and in the other two Cree coastal communities on diesel plants, those expenditures climbed to the point where they were in excess of $1 million a year, without taking into account capital additions for diesel generators and related equipment. The Department's position was further coloured by an unshakeable belief that it would ultimately be called upon to bail out the Wemindji Band when the latter proved unable to technically manage the integrated facilities - this despite the Band's known financial resources and, by then, its demonstrated ability to carry out and operate other significant projects in the community. The situation was further compounded by the absence within the Department of any ability to make a policy decision in this area or to develop one over the three or four years it took to bring the project on-stream.

Finally, the Department was unwilling to seriously consider the significant benefit to the local economy that the Mini-Hydro Project represented in that the outflow of cash to pay Hydro-Quebec energy bills would be avoided if a transmission line was not built.

THE WEMINDJI ELECTRICITY AGREEMENT

When it became clear that the Wemindji Band would build and implement the project, Indian Affairs had no choice but to back down and discuss the integration of facilities. While the Department maintained its formal position that it was not participating with the Band in a "joint" project, some funding to enable the Band to carry out certain upgrading and related works respecting the local distribution system was advanced. This funding came out of the annual portion of the capital envelope allocated generally to the James Bay Crees. An interim operating agreement was finally agreed to between DIAND and the Band in November 1984 after the project had reached its commissioning stage. Throughout this period, the Department insisted, in effect, on maintaining a parallel system based on the premise that the Mini-Hydro would not perform when and as expected.

In January, 1985, the Wemindji Band with the assistance of other Cree organizations in the territory, prevailed upon the Minister of Indian Affairs and Northern Development to appoint a special negotiator for the purpose of negotiating an agreement with respect to energy supply in Wemindji.

The parties reached agreement in principle in March of 1985 on a comprehensive agreement under which the Band would assume full responsibility for energy supply in Wemindji to both native and non-native residents for at least a ten-year

period. Subsequently, after intense lobbying in Ottawa by the Band, Indian and Northern Affairs forwarded a submission to the Treasury Board. The latter approved the Wemindji Electricity Agreement and authorized the Minister to execute same in November, 1985. The Band has since been forced, on three separate occasions, to re-negotiate with DIAND the payment schedule provided under that Agreement, but expects to finally execute the Agreement this March.

AFTERMATH

The Maquatua Mini-Hydro Plant came on-stream and within budget in January 1985 and, as planned, is now providing the basic electricity requirements for the community, as well as some of the heating requirements. Upon the execution and implementation of the Wemindji Electricity Agreement, the Band will implement a number of energy management policies designed to ensure optimum conservation of energy in the community. Funding provided under the Wemindji Electricity Agreement and through user fees collected pursuant to Band by-law will offset operating costs and enable the Band to recoup its investment within the initial term of that Agreement.

Within a wider framework of discussions concerning the supply of energy in the James Bay territory, the Band will engage in discussions which would contemplate reciprocal buy-sell arrangements with Hydro-Quebec of excess energy in the event transmission lines eventually connect Wemindji and two other Cree coastal communities to the main grid.

CONCLUSION

The Maquatua Mini-Hydro Project is, without doubt, the most significant project yet undertaken by the Wemindji Band. We are proud to be a part of the Small Hydro experience and to have had the opportunity to share that with you today. We are equally looking forward to challenges ahead in further developing the implementation of the long-term energy strategy for our community, the implementation of which will be a significant factor in both the social and economic development of our community.

John Lemieux is a partner in the firm, Byers-Casgrain of Montreal. He acts as a counsel to the Wemindji Band.
Walter Hughboy is Chief of the Wemindji Band.

PRIVATE EXPERIENCE

THE BURK'S FALLS SMALL HYDRO PROJECT

David G. de Montmorency and Bryan H. Bates
Galt Energy Systems
Cambridge, Ontario

WHAT IS BURK'S FALLS WATERPOWER CORPORATION?

Burk's Falls Waterpower corporation is a privately held Ontario company, which owns the small hydro generating station at Burk's Falls, Ontario, on the Magnetawan River. The company was set up as an investment vehicle by Galt Energy Systems Ltd., to attract capital to build a small hydro generating station.

Galt Energy entered into a contract with Burk's Falls Waterpower Corporation to build, on a turnkey contract basis, a small hydro generating station. In addition, Galt has also entered into a contract to operate, maintain and administer the project after it was built.

THE TENDER PROCESS

The site at Burk's Falls is owned by the Crown and administered under the Ministry of Natural Resources. The site itself had been tendered for small hydro development at an earlier time, but, the successful tenderer was not able to make suitable arrangements for the purchase of power or the development of the site. With the new policy of Ontario Hydro, effective January 1, 1985, stating that all surplus energy would be purchased by Ontario Hydro, with a first right of refusal for the purchase of power, given to the local municipality, the site was, again, put up for tender.

The tender documents were mailed out April 16, 1985, with tender closings on May 23, 1985. I'm including these dates to show you how tight the timing was in which to put this project together.

We took the next month to do our technical and economical analysis of the site in order to determine whether it was a feasible site to develop. We were fortunate in that the President of Galt Energy, Dave de Montmorency, had some prior

knowledge of the site and had visited it within the last two years.

Our first visit was to the Ministry of Natural Resources' offices in Bracebridge, Ontario, in order to determine the administrative procedure for the tender. We also discussed any restrictions with respect to the dam or surrounding land. We visited the community of Burk's Falls and had a meeting with the town clerk, who was most co-operative in supplying us with the history of the small hydro project. He also showed us a book called "Memories of Burk's Falls and District", which was most helpful in establishing this history. After our visit with the town clerk, we went directly to the site in order to take as many photographs as possible. We measured the actual head, looked at the dam and the old turbines, which were still in place. We then proceeded to contact Environment Canada in order to obtain daily flow data on the Magnetawan River to optimize the size of our installation.

After spending a considerable amount of time on analysing the flow data, from 1916 to 1984, we determined that the optimum size was a 1,000 KW system, which on an average basis would produce the maximum output 70.4% of the time. It was also determined that the used equipment, located on the site, would not be utilized.

The tender documents were finalized and submitted for the May 23rd deadline.

We attended the opening of the tenders at the Ministry of Natural Resources' office in Bracebridge and were very disappointed to learn that after all the effort put into our tender documents, we were the only people to submit an acceptable tender. The Ministry of Natural Resources then had 30 days to review our proposal from a financial and technical viewpoint. The Ministry was most co-operative in notifying us, within a two week period, our tender was accepted.

FINANCING THE PROJECT

We were aware when we considered doing a small hydro project that financing with a high leverage loan would not be possible. We had had many previous discussions with financial institutions and were aware that small hydro was seen as a new venture and had not been proven in the conservative minds of the financiers. We, therefore, proceeded on the basis that the site would have to be funded with 70% equity and 30% debt.

After determining the above parameters, we reviewed the possibility of proceeding with a limited partnership or a limited company. We had been working for sometime on obtaining approval for a small hydro project to qualify as an S.B.D.C. (Small Business Development Corporation) investment. We were

fortunate in having received this approval prior to the required investment.

The two ownership structures were considered. After working the numbers through, each came out on an almost equal basis. It was decided to go with the limited company, utilizing an S.B.D.C. because of the longevity of the incentive, rather than a straight tax deferral under the limited partnership rules.

We proceeded to put together an information package for prospective investors. The information package was put together in early June of 1985 and a few of the proposed investors were contacted and the details of the proposal reviewed. A meeting of the investors was set up in order to have an open forum for discussion.

We were pleased to have all but one of the people present at the meeting decide to invest in the Burk's Falls Waterpower Corporation.

We were fortunate to obtain the equity investors from business acquaintances and friends from the Kitchener-Waterloo, Cambridge area. By doing this, most of the people were familiar with Galt Energy Systems Ltd.'s small hydro developments, and, therefore, had the confidence in the technical and financial ability of the company to complete the project.

All of the equity investors were required to purchase their shares in Burk's Falls Waterpower Corporation prior to July 31, 1985. In order to facilitate this, we had share subscriptions signed by the proposed investors, with a meeting called for July 30, 1985. The confidence, by the outside investors, was demonstrated again by having the full subscription of shares, equalling $700,000.00, deposited into Burk's Falls Waterpower Corporation's account on July 31, 1985.

I should mention, at this time, that Galt Energy also holds a minority interest in Burk's Falls Waterpower Corporation. Galt's equity participation indicated to the investors that they were with the project on a long-term basis.

It was known from the outset that the equity investment had to be put in before the debt funding because the debt portion was going to be secured by the assets of the corporation. The debt funding could not be drawn upon until the project was substantially complete.

Four local financial institutions were approached to see if they were receptive to the debt funding on the project. We had a positive response from all four investment institutions because of the low debt to equity ratio and the future

potential for more small hydro projects to come on line. The five-year term of the debt financing was also attractive to the financial institutions.

With these parameters set, the four financial institutions made proposals to Burk's Falls Waterpower Corporation. We were able to arrange the loan at 11.25% over a five-year term.

With the above combined elements of:

- confidence in the turnkey installer
- low debt to equity ratio
- five-year term of the debt equity funding put in place before debt funding high asset ratio for security for the debt

it was relatively straightforward to put the financing package together.

TURNKEY CONTRACT TO INSTALL, MAINTAIN AND OPERATE

Burk's Falls Waterpower Corporation entered into a turnkey contract with Galt Energy, to install, to administer, to maintain and to operate the project.

BURK'S FALLS SMALL HYDRO SITE

"A local woodworking industry first used Burk's Falls as a source of power in 1885. At this point, the Magnetawan River, which rises in Algonquin Park, and flows into Georgian Bay, drops 28 feet. In 1904, a rock-fill crib dam was built across the river. The development was re-constructed in 1923 and new generating units were installed. The plant was owned and operated by Knight Brothers Ltd., a woodworking firm. In 1950, when the municipality became associated with the hydro system, the Burk's Falls generating station was acquired by Ontario Hydro. Continuing in operation for another decade, the 245 KW development was retired from service in 1960."
This information was taken off of a sign errected by Ontario Hydro on the site at Burk's Falls Dam, Burk's Falls, Ontario.

Small hydro was not new to the community of Burk's Falls. We found the residents to be most receptive to the proposed development and were most helpful throughout the project stages. I think the best way to tell you about the Burk's Falls site is to show you some slides of the project before development, and as it was being developed. Because Burk's Falls was a former small hydro site, it had some of the necessary civil components already in place, as you can see by the Burk's Falls Dam. There was also an eight foot thimble through the right-hand wing-wall of the dam. We decided to

locate the powerhouse opposite the old powerhouse. Concrete pipe was used for the eight foot diameter penstock because of the relatively straight and level distance that it was required to follow. We also found it to be the most economical for this installation.

The powerhouse is located approximately 300 feet downstream from the dam and its dimensions are 24 feet by 36 feet, with the floor of the powerhouse located above the 50-year flood level.

MECHANICAL AND ELECTRICAL EQUIPMENT

Turbines	Designed and manufactured by Galt Energy Systems Ltd. (2) 500 KW double regulated "L" Turbines 1320mm (52") runner diameter, 6.4M (21') long weight - 20 tons each Rated output 1,000 KW Runner speed 225 RPM Mounted 11 feet above tailwater in horizontal position
Gear Boxes	(2) supplied by Renold Canada with an 8:1 ratio
Generators	(2) supplied by Westinghouse Canada Inc. 750 H.P., 3-phase, 60 cycle, 600 volt, 1800 RPM with 200% overspeed for 5 minutes
Controls	Designed by Galt Energy Systems Ltd.

Switchgear supplied by Westinghouse Canada Inc.

ENGINEERING AND CONSTRUCTION

The engineering of the mechanical, electrical and civil work on the site was done by Galt Energy Systems Ltd., with some assistance from an outside consultant on the design of the powerhouse. Engineering of this site had commenced prior to the submission of the tender and went into full swing when we were successful with our tender in June of 1985. Some preliminary clearing of the site was commenced with soil testing in late August of 1985 and actual site excavation commenced in September of 1985. The longest lead-time items were the generator and gearbox, which had as much as six month delivery dates. These items were ordered in June of 1985.

The construction on the site went relatively smoothly. Local contractors were utilized for the bulk of the construction. With our rains in November and our early snows in December, there was some holdup on the actual construction at the site. We, in the waterpower business, have a reason for smiling when

it rains. Unfortunately, we did not smile during construction, with our record rains that we received during last Fall.

Our construction times were very tight and most people in the small hydro industry looked on what we were attempting to accomplish and said that it couldn't be done. To totally put together a 1,000 KW small hydro project, in a six month time frame, was unheard of. We can now look at the project and say that, yes, our timing was very tight, but we were able to complete the contract with a start-up date of late January, 1986.

OUTSIDE CONTRACTS AND REGULATORY APPROVALS

Because the site was released through the Ministry of Natural Resources, the bulk of the regulatory approvals had been done. The site was deemed to have very minimum environmental impact, therefore, a full environmental study was not required. We were, however, required to submit all drawings to the Ministry of Natural Resouces for their approvals of the site. We also were required to seek approval under the Navigable Waters Protection Act. We were working very close to the water on our development and there was some minor excavation at the water's edge, and, therefore, Environment Canada's approval was required. We are very pleased to report that all of the above regulatory authorities were very co-operative. It was also recognized that this was a new procedure and both sides were feeling their way to a certain extent.

We initially had some difficulty with the liability insurance requirements that the Ministry of Natural Resources had requested. This was not because of the project but because of the state of the insurance industry at this particular time. This difficulty was relayed to the Ministry of Natural Resources and in the spirit of co-operation, both sides mutually agreed on a satisfactory insurance level.

The revenue contract with Ontario Hydro was by far the most important contract in the proceedings. We were initially able to obtain a letter from Ontario Hydro, describing their policy that came into effect January 1, 1985. The policy stated that all surplus hydro would be purchased, based on their current policy of 3.3¢/KWH, but, in any month, if the capacity factor was under 65%, they would pay 2.3¢ for the entire month.

We requested that a meeting be held in the head office of Ontario Hydro in Toronto, in order to discuss the contract before its finalization. At the meeting, the following topics were discussed:

1. Buy-back rates for power, based on marginal costs rather than average costs.

2. Stated escalation rates for power.

3. Method of escalating rates for power.

4. Extended contracts to a 15 - 20-year term.

5. Flat rate contracts for a ten-year period at a higher average rate to facilitate ease of financing.

6. Method of approving the project by Ontario Hydro, prior to start-up.

7. The 65% capacity factor and how it is a deterrent to producing maximum power in some months.

All of the above were discussed quite openly, but, unfortunately, the gentlemen in the room did not have the authority to make any changes except for the extension of the contract for a ten-year term. They did, however, appear to be sympathetic to some of the discussion and felt that it should be open for future review.

The local municipality of Burk's Falls had the first right of refusal on the purchase of the power. The council felt the community was too small to enter into a contract of this nature. They were very dependent on Ontario Hydro for support and did not want to jeopardize this relationship in any way. We entered into a revenue contract with Ontario Hydro.

One thing that should be acknowledged at this time is, small hydro, like most relatively new industries, requires a great deal of patience and co-operation in its early stages. With this project, we had a great deal of co-operation and I would like to acknowledge some of the organizations that were a great deal of help, without identifying the individuals for fear I miss someone.

1. The community of Burk's Falls and their local council.

2. The Barrie office of Ontario Hydro.

3. The Bracebridge and Huntsville office of the Ministry of Natural Resources, along with individuals in the Toronto office of the Ministry of Natural Resources.

4. The local contractors who, at some times, were working under adverse conditions.

5. The management of Thompson-Heyland Limited, who assisted us on numerous occasions.

Without the patience and co-operation of the above people, this project would not have been completed.

The project is now onstream and we are smiling when it rains!

Bryon Bates is Executive Vice-President of Galt Energy Systems and David de Montmorencey is President of Galt Energy Systems of Cambridge, Ontario. Galt has an equity interest in the Burk's Falls Project.

FRONTIER SMALL HYDRO LODGE PROJECT

Pam Townsend, P.Eng.
P. M. Townsend & Associates
Elliot Lake, Ontario

The purpose of this paper is to present an account of the development of a small, private, off-grid hydroelectric powerplant in Northern Ontario. We shall endeavour in addition to outlining the history of the scheme to point out the problems encountered and experience gained that may be of benefit to similar future developments.

INTRODUCTION

Many of you may have heard of Frontier Lodge through the Ministry of Energy's recent advertising series promoting energy savings in various sectors of business and industry. The Frontier Lodge hydroelectric installation was featured in television commercials, and appeared in several newspapers and magazines last spring. The lodge is an excellent example of a privately-owned hydro project which is providing valuable cost reductions for its owner.

The installation is an 80 kW run-of-river scheme. It was funded by the owner, with a 25% grant from the Ontario Ministry of Energy, and with loan facilities from the Northern Ontario Development Corporation.

HISTORY

Frontier Lodge is a well-established Tourist Lodge some 30 miles north of Elliot Lake. It was originally constructed over 50 years ago as a logging camp and has since that time been in business as a tourist and hunting facility complete with outpost camps. The present owners John and Betty Middleton have owned the lodge for about 12 years.

The lodge is a 5,6000 sq. ft. two storey timber building comprising dining room, lounge, bar, kitchens, living quarters for the owners, laundry, and twelve bedrooms. In addition, there are 14 adjacent cabins, some log and some timber-framed and sided. Most cabins have two bedrooms, sitting room, kitchen and bathroom. The lodge also operates a fly-in outpost

camp some 40 miles to the north. The lodge is open year round for fishing, boating, hunting, snowmobiling and camping.

In the original lumbering days, there were, of course, no transmission lines in the area, but during the development of the Elliot Lake uranium mines in the 1950's, Ontario Hydro brought lines in to service the town and mining developments, but they stopped 20 miles south of the lodge at Rio Algom's Quirke Mine. A series of diesel generators continued to supply power to the lodge for the next twenty-seven years. This was supplemented by wood and propane for heating purposes.

The lodge is situated on McElrea Lake, which is linked by Rottier Creek to Rottier Lake at an elevation some 100 ft. higher. Rottier creek is approximately 2,200 ft. long.

The possibility of installing a hydroelectric generator on Rottier creek was first given serious consideration by the Lodge's original owner, Mr. Stuart McElrea in 1958. However, plans did not get any further than a survey of a possible powerhouse location, and budget quotations for the turbine from Charles Barber Co.

The present owners saw the possibility of generating their own power using the available water had almost from the start of their business, and they approached Barber for quotations again in the early 1970's.

In the meantime, any real progress on the scheme was slight. The Middletons' hunch that the project was worthwhile was eventually substainiated in 1977 when they commissioned an engineering feasibility study. This report showed the project to be viable, but it hinged on the use of storage capacity in a lake upstream, where an existing MNR dam controlled the water level. Unfortunately, at about the same time, this dam was declared unsafe and was subsequently removed. The project then seemed to flounder, and it was not revived until the winter of 1980/81 when the rise in diesel fuel prices began to be a serious financial burden to the lodge's operation.

The one worthwhile area of progress of these years was that the Ministry of Natural Resources granted location approval for a structure at the head of Rottier Creek.

GRANT APPLICATION

In 1982, Mr. Middleton requested P. M. Townsend & Associates to assist him in applying for grant funding from the Ministry of Industry and Tourism under their Industrial Energy Conservation and Oil Substitution program. Unfortunately, only about 3 months of the program remained, and an updated feasibility study was required to demonstrate that the proposed project was economically feasible and that it fell within the funding guidlines. The following information was needed:

1. Possible generation capacity of Rottier Creek.

2. Installation costs esimate.

3. Costs savings estimates.

4. Approval in principle from the appropriate regulatory bodies.

GENERATION CAPACITY OF ROTTIER CREEK

During all the years of discussing the possibility of a Hydro Installation, no actual flow measurements were made for Rottier Creek, and no lake level records were kept. Attempts had once been made to build a measuring weir on a straight stretch of the creek between steep rock walls, but on the 25 ft. wide creek flowing 2-3 ft. deep, the construction of a weir by hand had been a major undertaking, with only limited success.

The weir always leaked badly and no useful readings were obtained. By the time the scheme was reactivated in 1982 the weir was totaly derelict.

With the short time available for assessing the capacity of the creek, it obviously was impossible to assemble reliable flow readings on which to base the 95% firm flow.

This aspect was therefore approached from meteorological and hydrological records, with a parallel measuring program using the float method. The watershed area for the creek was computed from topographic maps and the monthly mean streamflows were deduced by comparison with Ministry of the Environment data for a similar watershed on the Serpent river system some 15-20 miles south. The simple float flow-measuring system was operated for the next 15 months.

The float system was installed in the most accessible, straight and smooth-flowing section of the stream. A surface float was timed over a set distance and concurrent water depth measurements were made at control points, weekly.

By accurate measurement of the bed profile and several velocity profiles, it was possible to establish a factor by which to correct the surface velocity to mean stream velocity.

At the end of the 15 months measurement period, the actual flows were compared with those deduced from MoE data, and correlation was found to be good. These deduced and actual measurements were used in the application for a water-taking permit, which was granted without any problems.

It was decided by examining the pattern of low-flow measurements over the past 10-14 years, in sizing of the turbine, that an 85% firm flow would be acceptable, especially

as the lodge's power needs were at a minimum during the mid summer low periods. The 85% firm flow based on the above data is 10.6 cfs.

A surveyed traverse between the two lakes confirmed the gross head difference to be 102 ft. After examining pipe characteristics and costs, a 20" diameter Sclairpipe was selected. Estimated friction losses in the pipe amounted to approximately 10 ft., leaving a net head of 92 ft. and a maximum generating capacity over 80 kW.

CONSTRUCTION COST ESTIMATE

The cost for supply and installation of the system were estimated and quotations obtained from manufacturers for the turbine and other rotating equipment and for the pipelines. Total cost of the project was estimated to be $202,000, with a breakdown as follows:

Site preparation and roads	11%
Pipeline	24%
Turbine, generator and controls	32%
Intake works and powerhouse	8%
Transmission line	5%
Upgrading existing electrical facilities	10%
Engineering	10%

In addition to the above estimates, Ontario Hydro was approached to provide a figure for installation of a transmission line from the closest grid connection point to the lodge. Their estimate was a mere $900,000, confirming that connection to the grid was not the answer to the lodge's problems.

COST SAVINGS

The cost savings from the switch to hydro power were estimated using average consumption figures for the previous several years with the then current prices for diesel and propane and other supplies.

A summary of annual savings at 1982 prices follows:

Diesel fuel 44,000 litres	$16,000
Generator Supplies & maintenance	2,750
Propane fuel 35,000 litres & tank rental	9,050
Woodcutting labour, tools & maintenance	2,200
TOTAL	$30,000

The turbine supplier provided an estimate for annual running costs for the turbine and associated equipment of $2,000.

APPROVALS

At this early stage, it was considered prudent to contact all ministries with jurisdiction over Lakes and Rivers to ascertain any concerns they might have in order that these could be given full consideration during all stages of the project, and so that delays in approval would be minimized.

Fortunately, neither Rottier nor McElrea Lake is of special significance from a fisheries point of view, and Rottier creek is not a fish migratory route because of the 27 ft. waterfall midway along it.

Rottier Lake is too small to consider for storage capacity since it could provide only a week's supply of water for the proposed turbine. The installation was therefore designed to operate as a run-of-river scheme, with only a small buffering capacity in Rottier Lake.

The requirements of MNR and MoE with regard to allowable drawdown and maintenance of stream flow coincided with the owners' intentions on these matters, especially as the business of the lodge depends largely on the local fishing, and on the scenic beauty of the lakes.

LOAN AND BRIDGING APPLICATIONS

A grant of $50,000 was awarded to Frontier Lodge by the Ministry of Industry and Trade for the development of the Hydropower scheme as outlined above. The grant was to be payable on completion of the project.

Having secured a grant, the next step was to arrange the balance of the financing. The lodge had no surplus capital to invest in the project.

After some research, it was determined that the Northern Ontario Development Corporation (NODC) had the most attractive, and probably the only suitable loan program available. A tourist term loan was applied for.

Although a substantial grant had been awarded, the difficulties of obtaining the loan, conditions attached to both loan and grant requiring the project to be 100% complete before any money was advanced, and the near impossibility of obtaining $200,000 bridging finance almost caused the project to flounder at this stage. It was only the persistence of the project team, the confidence of the owner, and the valued support of Mr. John Lane, MPP, which brought the scheme through this difficult period.

NODC was of course provided with the previous three years' financial statements, statements of the owners' net worth, and the current engineering feasibility study, but their surprise

at the nature of the project prompted us to provide several other items. A professional appraisal was made of the current market value of the lodge, cabins and outpost camps. This proved to be critical, since neither NODC nor any of the institutions approached for bridge financing was prepared to attach any value at all for collateral purposes to the proposed $200,000 installation.

A projected cashflow analysis for the next 15 years was made using Ministry of Energy extrapolations for future oil prices.

Finally, a report detailing the benefits of conversion from diesel to hydro was prepared, from a point of view of improving amenities for tourists. (By 1982 the lodge could afford to run their generator only in the evenings, or perhaps all day at weekends if the number of visitors justified it,) This last report in retrospect appears to have stated the obvious to those people still living with diesel generators, but for most of us on the grid system with 24 hour a day power it is difficult to appreciate what living with electricity for only a few hours a day is like.

BRIDGING

A loan for $150,000 was awarded by NODC in May 1983. Certain conditions were attached to both the loan and the grant, allowing payment only on total completion of the project, and therefore necessitating a $200,000 bridging loan.

The FBDB and various chartered banks were approached - but in all cases the nature of the project was totally beyond their experiences; and although professionally prepared feasibility studies showed it to be very worthwhile, and financial data showed the lodge and its owners to be in good standing, and both NODC and the Ministries had given it guaranteed financial support, the banks were still unable to provide the needed financing. Unfortunately, the banks were very unsure of whether or not they should be saying no, and they wasted much valuable time in doing it.

By September 1983, the owner still was unable to arrange bridging, and by then time was beginning to run out for the project. The MIT specified completion date was 30th November 1983.

Focus was turned to preserving the grant until the next construction season. This was made possible by the Ministry of Energy agreeing to administer it under their Small Hydroelectric Demonstration Program. It was also at about this time (winter 83/84) that NODC finally agreed, because of the unavailability ot bridging financing, to provide their loan on a staged basis during construction. Payments were to be made on certification by the engineer of work completed. In January 1984, the first firm materials orders were placed.

CONSTRUCTION

Two years had elapsed between the feasibility study and the start of the construction, and the budget for the scheme had remained exactly the same. Further, owing to the private source of funding, absolutely no increase was possible.

These factors necessitated tight financial control on all aspects of the project, with no frills. Fortunately, however, the price of the turbine and associated equipment had risen only slightly, and the pipe supplier lent support by maintaining his 1982 price.

A blow was dealt to the finances of the project via a back injury to Mr. Middleton in the early spring; and he could not contribute the amount of his own labour originally anticipated. The site preparation, access roads and pipeline contract therefore had to be expanded. Reductions were made wherever possible throughout the other sections to compensate for this.

Actual total project cost was approximtely $205,000 and the final breakdown was very close to the percentages estimated as outlined above.

After the difficulties encountered in financing the project, the construction phase seemed to be the easy part of the work. Construction began immediately after completion of the engineering drawings and subsequent MNR approval in the summar of 1984.

PIPELINE

The 33 x 55 ft. lenghts of 20" diametr Sclairpipe were the first capital items to arrive on site. These pipelenghts, each weighing half a ton, were offloaded from the transport by hand, using six men and ropes.

The pipe route through the bush, two pipe fusing yards, and an access road were cleared by the owner, using a borrowed D-6. A contract then was awarded for improving the rough right-of-ways as required, fusing and installing the piping, and constructing the concrete slab powerhouse foundation.

The pipe was fused into four sections of abour 450 ft. each. These were towed into place by tractor, and then bolted up at two flanged connections, and at the main inlet butterfly valve. The pipe was positioned on sleepers which were bolted to rock where possible. Two short sections of the line in steep sloping areas were buried in a sand berm. Apart from a short high point on the route, which required blasting, it was possible to lay the pipe at a continuous downslope from intake to powerhouse. All sections of the pipe are below upper lake level. At the one crestpoint an air release valve was provided for use during filling of the pipe.

INTAKE

The steel intake transition was fabricated in Elliot Lake. It consists of a 3/4" screen 6 ft. x 4 ft. in area, with a 12 ft. transition taper which clamped onto the open Sclaipipe end. The intake lies in 12-14 ft. of water, approximately 80 ft. from the shore of the upper lake. In this position there is little risk of the grating being blocked by leaves or beavers, and no danger of ice damage. It also takes relatively warm water from below the thermocline during winter months. One serious consideration during design of the project was whether freezing was possible in the penstock during winter cold snaps. The intake line leaves the lake through the low point in the creek bed, with no control structure being needed. It follows the creek for 500 ft., then leaves it for a more controlled route of descent, when the creek approaches the falls. The powerhouse is located in the position on the shore of the lower lake which gave the shortest penstock route, and the most direct line of the lodge for the power transmission cable.

POWERHOUSE

The powerhouse structure is a 12 ft. square blockwork and timber building set into the slope beside the lakeshore. The building has a 16" thick reinforced concrete floor slab, to which all rotating equipment is bolted. This allowed the final 100 ft. of penstock to be buried, and the thrust block to be integral with the slab.

The turbine, for ease of access, was lowered into place with the powerhouse only half built, although it can be broken down for removal through the door if necessary.

It was at this point in the story that the Ministry of Energy's TV commercial was made, and the installation was carried out with cameras rolling, under the instruction of a camera director, rather than the engineer. By the time we reached take #6 the turbine was being installed in an expert 90 seconds!

MECHANICAL EQUIPMENT

The generating system, manufactured by Galt Energy Systems consists of a 12" fixed pitch propeller turbine with regulating wicket gates, belt driving an 80 kW 3 Ph Kato generator at 1,800 RPM. The system is governed by an electronic load controller by Thompson & Howe, which uses the wicket gates as control elements in combination with a 72 kW load dump.

Water flow to the turbine is controlled by a 20" butterfly inlet valve operated by a 12V electric actuator. This device also acts as the emergency shutdown, driven from a storage battery. The start-up and non-emergency shutdown of the plant is manual. Emergency shutdown via the main inlet valve occurs on turbine overspeed, loss of bearing cooling water,

overheating of the load dump, or system off frequency.

The manner in which the control system operates allows a minimum power generation of 25 kW at maximum wicket gate closure. Any power not required by the lodge is converted to waste heat in a hot water tank, which is piped into the outfall. At power levels above this minimum the wicket gates become operational.

If for any reason the flow of water to the turbine is stopped at the powerhouse valve, a 6" bypass opens simultaneously, allowing flow to continue in the penstock - an important consideration in winter when otherwise the line most certainly would freeze, causing total shutdown until spring. A secondary benefit of this bypass is the elimination of pressure transients, the penstock water velocity stays essentially constant.

There is a main inlet valve at the upper lake, together with an air inlet/release valve to allow the line to be totally emptied if necessary.

Power is generated at 600V and is transmitted to the lodge at 4200V, where it is stepped back down to 220/110. The old diesel generator remains as a standby at the lodge, it can be switched back into the system to take over at maintenance periods.

The Frontier Lodge Hydroelectric Scheme became operational in December 1984, and has been providing all the lodge's energy requirements since that time.

SUMMARY

We would summarize the Frontier Lodge Hydroelectric Project as having been a relatively straightforward scheme to construct, but a difficult concept to finance.

The major hurdles overcome during the project related to cashflow and financing guarantees, and the biggest of these lay in the fact that each stage of the financial arrangement had to be completed before the next stage could be started. A great deal of time was spent before any significant engineering work could be done or any orders for equipment placed. It is worth noting here that the manufacturing and testing period for a one-off generating system is approximately six months.

Approvals from the various ministries were straightforward once the engineering drawings were available. These approvals were issued within weeks in most cases, and they did not cause significant delays. All ministries were most helpful whenever advice on regulatory matters was sought.

Ingenuity and very tight expenditure control was necessary to

ensure the project stayed within budget. Properly executed contracts, even for relatively small amounts, were useful in forestalling claims and in defining the scope of work expected.

We hope that the fact that this project has been successfully completed by a private individual will give confidence to other developers and their financial supporters in a similar situation. The achievements of John and Betty Middleton, and their continuing costs savings will be an inspiration to others in Ontario with untapped Hydro potential, to go out and develop it.

Pamela M. Townsend, B.Sc., ACGI, C.Eng., P.Eng.

Pam Townsend is a professional engineer who established P.M. Townsend and Associates in 1981. Located in Elliot Lake, the firm specializes in civil, structural, and building engineering.

PRIVATE DEVELOPMENT OF HYDRO POWER IN BRITISH COLUMBIA

MOSES INLET EXAMPLE

Glenn S. McDonnel, P.Eng.
Sigma Engineering Ltd.
Vancouver, British Columbia

1. OVERVIEW OF SMALL HYDRO DEVELOPMENT IN BRITSH COLUMBIA

Small Hydro Power projects have been used in British Columbia since the late 1800's. Their use increased in the early part of this century, but the growing availability of diesel engines for small load centers and the expansion of the provincial grid serving most large load centers led to a widespread decline in the use of small hydro. The situation began to reverse in the mid 1970's. Increasing oil costs affected remote communities of all types, while electricity prices also rose. The realization came that something needed to be done, but as is shown later in this paper, there can be a considerable lag in the realization of a problem and its solution.

By 1985, a considerable number of projects had been built, and an increasing number were using Canadian built equipment. Provincial records show that in the years 1975-85 some 57 projects under 25 kW representing 42% of the total were licensed while 23 projects larger than 25 kW had been licensed also representing 42% of the higher range. During this period several provincial and federal programs were established which catalogued information which could be of use to the small hydro developer as well as providing other means of assistance.

The Moses Inlet Hydro system is an example of a project which has been entirely funded privately from the final design stage through commissioning. However, the project may not have been possible without the assistance provided by the Remote Community Demonstration Program (RCDP). The potential of the site was recognised and catalogued in the Energy Overview of Remote Communities British Columbia and this led to the site being studied as a demonstration project by a private development company. The funding provided at this feasibility level by the RCDP allowed an exhaustive study to optimize system design and explore means of developing the site for the mutual benefit of the investors and the site owners.

This paper describes the building of the project and outlines

some of the unique problems that were encountered because of its development in the private sector for lease back to a large company.

2. MOSES INLET HYDRO POWER PROJECT

2.1 BACKGROUND

The Moses Hydro Power Project had been under consideration for several years, beginning in 1982 when a private contractor initially approached Crown Forest Industries Ltd. with the idea of developing the hydro power resource to serve their forestry camp located near Ebert's Cove on Moses Inlet about 125 km North of Port Hardy. Subsequently the site was recorded in the Remote Community Demonstration Program's Overview Study for British Columbia, sponsored by Energy, Mines and Resources Canada.

The Remote Community Demonstration program also sponsored a study which concerned the feasibility of developing the hydro power resource at Moses Inlet from the viewpoint of the private investor. This study looked at both the technical and economic aspects of the development and it has formed the basis of subsequent work. The study concentrated on developing the optimal size of project considering the variables of hydrology and demand.

Shortly after the feasibility study was completed in March 1984, a Lease Contract proposal was made to Crown Forest. The contract essentially involved construction of the project for Crown Forest, then Crown would pay graduated quarterly lease payments for 10 years. After the application of a buyout clause the ownership of the hydro power plant would pass entirely to Crown Forest.

While details of the contract were being discussed, some preliminary work on the project was authorized by Crown Forest in order to expedite the construction once all approvals were obtained. Preliminary work included applying for land use permits and water licences, obtaining quotations from turbine suppliers and related liaison.

2.2 DESIGN

The design of the Moses Project was relatively straightforward, and was dictated by the optimization criteria. The preliminary design used in the feasibility study was based on coarse mapping and one field inspection conducted in poor weather. However, the few variables in routing allowed the forest company to extend the existing access road to the vicinity of the intake. This allowed the location of the intake to be optimized relative to the expected costs of the penstock and the powerhouse, and resulting power output. Power output was a function of both the head and the location, as lower heads also had greater flows.

Once the locations were optimized, the design task involved material selection, sizing and final location. Most of the penstock could be built as buried PVC water pipe, which is usually the least expensive pipe system. The upper reaches of the penstock presented a more typical problem: Water had to be carried from the intake on a downward slope as well as remain clear of the creek, however road access was on the left bank, while the predominant part of the upper penstock and the intake were on the right bank. The constraints dictated that polyethylene pipe supported by rock saddles and wood trestles would be used. It was convenient for hand placement in rough terrain and the coupler joining system avoided the use of fusion which needs high quality control standards not easily attainable on the site. Once clear of the area only accessible on foot, the polyethylene pipe was maintained over a length of rough and unstable ground prior to converging to PVC.

The intake design criteria consist of maintaining flow, freedom from icing and sediment separation. These factors were achieved while minimizing creek disturbance by using a large diameter culvert section, with a bottom sediment outlet and trash screen. The culvert was placed in a shallow excavation at the side of the stream channel, then back-filled to restore the intake pond.

The powerhouse design was dictated by several local concerns. The forest company required a new powerhouse for its existing diesel generators and these were to be incorporated under one roof, thus making convenient synchronizing with the hydro turbine possible. Special isolated inertia blocks were used to dampen vibrations from the diesels. The building was wood frame (without a crane) because the location was accessible.

The station electrical design is the most important aspect of the system, because it is responsible for maintaining an optimal delivery of hydro power. The camp potential load far exceeds the capacity of the hydro turbine, but by managing the load to reduce peaks and using the diesels for load peaks that do occur, the delivery of a maximum amount of hydro power can be obtained. When the loads approach the hydro plant capacity, the diesel will start up automatically and synchronize. Then with increasing load, the diesel will take up the amount of load which exceeds the hydro plant capacity and shut down when loads are below the hydro plant capacity. Control of the turbine operating below its capacity is obtained with a jet deflector and with a manual needle valve to reduce flows in the event of low streamflow.

2.3 CONTRACTING

Construction

The Moses Project was contracted in several stages, and involved the assistance of the forest company for the provision

of site services (accommodation, equipment, fuel) as well as the site preparation. The intake, penstock and powerhouse contract was awarded first, followed by the turbine/generator contract. The electrical installation contract followed later, as it was dependent on input of design information from the turbine supplier and was not needed until just prior to the turbine installation.

Leasing

The above contracts were governed by a master agreement between the owner and the forest company. This covered terms of payment, timing, guarantees and maintenance and was the basis by which the work could proceed. The agreement provided for a schedule of lease payments to be made to the owner commencing when power became available. Such agreement was also necessary in order to secure third party financing of the project.

2.4 CONSTRUCTION

Construction work was initiated in November 1984 with the intake, penstock and powerhouse contract. Aside from the usual weather problems, no major problem was encountered until January when the backhoe was damaged digging the penstock trench in frozen ground. It was then realized that the machine was too light for the task. Work was delayed until the forest company's large backhoe was available, and the contract was completed in mid March 1985. A total elapsed time of about 45 days was needed for the work. The delays did not cause any disruption in the overall schedule, as the turbine contract was not scheduled to finish until later.

Toward the end of construction, the forest company connected a domestic water system to the penstock, to serve the camp through a pressure reducing valve. In addition several standpipes were installed on the same line for fire protection.

The electrical installation began in June 1985, while the turbine was installed in July 1985. Final commissioning was not possible on the scheduled date of August 1, 1985, due to problems beyond the control of the developer, namely prolonged drought and difficulties with the equipment supplied by Crown Forest for automatic starting of the diesels.

Full time supervision was provided for the civil works portion but only final inspection and commissioning/testing inspection was provided for the electrical and turbine installation.

2.5 OPERATING EXPERIENCE

At the time of writing, there was limited operating experience on the system, but it had been completed and was in the fully operational automatic mode. The Operation and Maintenance Manual assists the camp personnel who handle the day to day

system operations and detailed record keeping on both maintenance and power production is to be made. Provision of specialized maintenance and nonroutine repairs is to be made by the project developer.

2.6 PROJECT SUMMARY

Moses Hydro Power Project

Capacity:	75 kW
Gross Head:	95 m
Penstock:	
Length	750 m
Sizes	250 m of 250 mmøpolyethylene Series 60 250 m of 300 mmøPVC Series 100 250 m of 250 mmøPVC Series 160
Intake:	Corrugated steel side channel culvert with coarse trash racks, sediment outlet, shutoff valves and air vent.
Powerhouse:	6 x 9 m wood frame, steel clad with concrete slab. Houses 1-100 kW diesel generation set, 1-60 kW diesel generator set and 1 - 75 kW hydro turbine/generator. Roof design for 90 psf ground snow load.
Turbine:	75 kW Dependable Turgo Impulse Wheel, 375 mmø.
Generator:	75 kW Kato 3 phase 120/208V, 900 RPM (to match diesel generator voltage).
Governor:	Thomson and Howe Product G (electronic) with hydraulic jet deflector. Manual needle valve.
Transmission Line:	4160 Volt 3 phase buried line, 150 m long. Step up and step down transformers.
Energy Management:	Thomson and Howe Product C priority load controller with derated water heaters.
Alarms:	Hydro Turbine: Under/over frequency, under/over voltage, overcurrent (on breaker) shaft vibration, bearing temperatures (4), reverse power.

Diesel Generators: Overcrank, overspeeding, high water temp, low oil pressure, reverse power.

General: Fire alarm, Penstock Pressure Alarm, Remote Alarm annunciation at camp.

Operating Scheme: Turbine carries base load of camp, with output governed by camp demand or stream flow. Excess flow is deflected.

Loads exceeding turbine capacity activate Product 'C' load shedding, which in turn causes one diesel to start up and synchronize (diesels can have priority alternating, but usually the smaller diesel would be used to be most fuel efficient for the incremental load). Product 'C' turns loads back on in reverse priority which are picked up by diesel. Decreasing load activates load dump, then shuts diesel.

2.7 CONSTRUCTION COST SUMMARY

Preliminary Engineering Studies			$ 20,000
(The nature of the project required more analysis of options than would normally be required, leading to significantly higher cost at this stage)			
Design, Tendering, Supervision and Contract Management			$ 47,500
Construction			
Intake		$ 14,000	
Penstock		62,500	
Powerhouse (including space for diesels)		39,000	
Turbine Generator (Supply and Install)		87,500	
Electrical Installation		46,000	
Site Services by Forest Company	(Est.)	10,000	

Extra Work	3,000	
Installation/Commissioning	3,000	
Protection and Monitoring	INCL.	
Domestic Water and Fire Protection	2,000	
		267,000
		$334,500

2.8 CHRONOLOGICAL SERIES OF EVENTS

	Design/Construction	Contracts
May 82	Initial approach by others	
Mar 83	Location noted in RCDP study	
Jun 83		- Initial proposal to study
Aug 83		- Application for EMR funding.
Dec 83	First site visit, prefeasibility study	Approval of EMR funding
Mar 84	Completion of Feasibility Study	
Apr 84		- Initial Lease Contract Proposal
Aug 84	Turbine Tenders close	- Partial go-ahead for design
Sep 84	Civil Works Tenders close	
Nov 84	Civil Works begin	- Partial go-ahead for Civil Works
Dec 84	Turbine Contract Award	- Continuing Lease Contract negotiations
Mar 85		- Financing letter of commitment - Contract executed
Apr 85	Electrical Tenders	
Jun 85	Electrical Installation	- Financing delivered

Jul 85 Turbine Installed

Sep 85 Drought ends, turbine on Manual Synchronize

Nov 85 Electrical Installation of Auto Start complete

3. PROBLEMS ENCOUNTERED IN THE MOSES INLET DEVELOPMENT

General

Reference to the chronological history of the project in Section 2 shows that there are two sides to project development, a design/construction side and a contractual/ legal/financial side. Although these activities often proceed concurrently, they should ideally have several crossover points which provide logical breaks in both construction and contractual activities before further activities are undertaken. In practice, despite the best efforts to match the contractual activities with construction, delays occurred, and the resources of the developer were necessary to forestall problems which could have threatened the project completion.

Approvals

The nature of private hydro power development requires several approvals from different types of agencies. The level of approvals depends on the project structure. A well financed owner, building his own project, only requires approvals from government agencies, such as a water licence, land occupation permit and perhaps energy regulation approvals. These approvals must be undertaken for almost all hydro power projects in Canada, and they will not be elaborated here, except that in the case of Moses Inlet, which had no conflicts of water or land use, the water licence which should normally take 3 months to process actually took 7 months.

Contractual Matters

Levels of approvals begin to mount up when third party financing and development are utilized. A contractual relationship must be established between the project beneficiary (in the Moses Inlet case, Crown Forest) and the developer to first build the project and then upon completion, either sell, operate or lease back the facility. Depending on the sophistication of the parties and how many lawyers they employ, the contract can potentially be long and drawn out over relatively simple concepts. Key points to cover include the design of the project, level of involvement of each party during and after construction and finally the cost of the various aspects of the project before and after construction.

Financial Matters

In most third party developments, there becomes a fourth party involved, the financier. Financing can be provided by banks, leasing companies, private stock placements, limited partnershps and development agencies. This paper will deal with situations found with lending institutions of all types. The lending institution has several requirements to establish financing:

- Equity participation must be shown by the borrower;
- The project must have demonstrated cash flows to cover the payments to the lender;
- Alternative security must be provided.

It is the matter of alternative security which often poses the most difficult problems. Small hydro projects, especially in British Columbia, tend to be in remote areas and only benefit a local load center which may not always appear to be a permanent customer. The project itself is only of benefit to the local load center and salvage values are a fraction of what the project costs. Often alternative security will be required from the project developers in order to ensure that funds can be advanced, such as corporate and personal guarantees of the developers, and guarantees from the project beneficiary. In addition, evidence of licences, meeting of conditions precedent, valid contracts and assignment of rents (requiring acknowledgement of the beneficiary) may be required. In the Moses Inlet project the security involved 2 debentures, a tri-partite agreement, and 3 levels of corporate and personal guarantee. This documentation was required for a loan value in the same range as a mortgage on a large house and required an additional 7% (when finally added up) in legal and management fees to negotiate the details. The financing was concluded when the project was only one month from completion. Recent financing for a different project undertaken required 2 debentures, 3 assignments, guarantees, opinions of the lender's lawyer and confirming resolution by directors, signature certifications and consents to assignment.

The financial matters were only resolved with a great deal of effort on behalf of the project manager and the beneficiary's personnel, plus some understanding contractors who were late in getting paid. All this occurred despite the fact that the initial financial proposal was obtained 6 months before completion of financing and developer/beneficiary agreements were initiated more than one year before completion of financing. The project was at a stage and had so much commitment by all parties that compromise and completion of the deal were in everyone's best interest.

The main point of the problem is that time passes by while all

of these "office type" activities are occurring. The contractors on the project were not responsible for any delays, only the various administrative levels. Had the developer waited until all of the approvals were properly in place, the project would certainly have taken much longer. Many times the constraints of winter weather prevent efficient construction, so too much delay in start-up could delay the whole project a full season.

What transpired was that the good faith and intentions of all parties to successfully complete the project held true. Had it not been for these personal commitments by personnel of the developer and the beneficiary, the project could not have been completed.

Operating Costs

The control of financing will usually determine whether a project can be completed, but the control of operating costs will determine its ultimate financial success. In particular, insurance and repair costs are areas that have the least amount of control.

Insurance for property and especially liability has been subject to some dramatic price increase in recent years. The costs of recent settlement claims is now being borne by present policyholders. Although a private owner could take some risk by perhaps limiting the amount of insurance he carries, a third party developer must satisfy his financier and the project beneficiary that the project is fully insured. Optional packages exist for covering loss of lease revenue and machine repair but coverage for the quality of delivered power is usually not available. However, most projects should have enough electrical protection to prevent electrical damage to the electrical load devices.

Repair costs are the other area of uncertainty. Most repairs are expected to occur in the powerhouse with electrical and mechanical devices the most problems. At Moses Inlet a situation arose which was not anticipated, with the failure of two reinforced PVC tees on the penstock at separate times. Both tees failed by their gasket retaining rings blowing out resulting in rapid leakage and ground softening. Although repairs are relatively straightforward and the value of materials is not excessive, the total repair cost can be high. The second tee failure at Moses Inlet occurred when the plant was operating and when temperatures were well below freezing. The result was that heavy equipment had to be brought in to break through frozen ground, repairs took longer, the failure occurred in a weekend, leading to a parts shipping delay, and there was a penalty paid for plant downtime. The resulting costs were over $5,000 for the repair of a fitting initially worth $250. Had the site not been remote, the cost of repairs may have been about $1,500.

The more typical repairs involve the electromechanical system. The Moses Inlet system is relatively complicated and there are numerous locations where problems could occur. While one could advocate a simpler system the nature of the project is to demonstrate something new, and these risks must be absorbed by the developer.

4. SOLUTIONS TO TYPICAL PROBLEMS IN SMALL HYDRO POWER DEVELOPMENT

General

Most of the problems outlined in Section 3 do not have a direct solution but they do have means by which the developer can lessen the risks and complications. These techniques should always be attempted because so much of the project is beyond the direct control of the developer that organisation plays a key role.

Development Problems

The first step is to plan the development and recognise where time delays occur. Government approvals, financial approvals and contracts with the project beneficiary must all be arranged in their proper sequence. Ideally, all of the development activities such as design, turbine/ generator procurement and on site construction should not proceed until all approvals are in place. The complications that arise include:

- The inability to fix development costs, hence development contract signing, until all prices are submitted;

- The inability to secure financing until costs are known, approvals are completed and development contracts are signed;

- Long lead times required for equipment ordering;

As more small hydro projects are developed costs will become better known, and the estimating risks inherent will decrease, but at the present time, the uniqueness of each project means that tendered costs must be relied upon. Realistically these contractual activities should not take as long as they do, but if they are expected to be lengthy, the developer can:

- Start government approval processes early;

- Be well backed financially;

- Design contracts for fast approval by all parties, but giving them a ceiling cost;

- Determining well in advance the financier's requirements, and making the beneficiary of the project aware of his involvement with the financing through guarantees and assignments.

- Plan for construction activities early in the season to provide a cushion against delay;

- Be prepared to take financial risks if the various approval delays threaten to adversely delay the entire project;

  Do not sign performance guarantees unless they are well qualified to reflect the adverse impact of events beyond the control of the developer;

- Try to fix legal and financial requirements and fees in advance.

These do's and don'ts can also be assisted by the developer keeping good records of his design and financial activities. Most approving agencies, including financial agencies, will want to check the technical viability of the project and the financial viability. Having the information readily available and in a good format will help to ensure faster approvals.

Operating Costs

The control of operating costs is an ongoing problem and the developer has some choice in the costs he undertakes provided the development contract is written accordingly in advance. Insurance is a major uncertainty, and beyond the control of both the developer and the beneficiary. The best means of control is to ensure that the insurance requested is at a minimum acceptable level and that an escalator clause be provided to provide cost sharing between the developer and beneficiary beyond a certain premium level.

Repair costs are influenced by several factors, including the natural hazards of the project, the quality of the equipment utilized, the personnel utilized in maintenance, the frequency of maintenance, the accessibility of the project. Some of these factors, such as natural hazards and accessibility cannot be reduced directly, but the project design can take into account some of these problems to make maintenance easier. Examples include the use of powerhouse cranes for maintenance in some situations, provision of intake cleanouts and in general providing adequate access within the site.

Mechanical repairs can never be eliminated, but their frequency and severity can be reduced by:

- Utilizing reliable and simple to maintain equipment;

- Providing regular (say annual) technical inspections of components and operating procedures;

- Ensuring that maintenance personnel carry out the manufacturer's recommendations and maintain records;

- Obtaining equipment which can be serviced by local manufacturer's technicians.

The developer, if he agrees to provide some degree of plant maintenance, must control his costs partly through his contractual provisons with the beneficiary. Most small projects depend on on-site personnel to do part time inspection. This is necessary to keep costs under control. The maintenance portion of the development contract must detail precisely the various roles of developer and beneficiary and from the developer's viewpoint, as many activities as possible, except for the annual technical inspection, should be left with the beneficiary.

5. BENEFITS OF PRIVATE SMALL HYDRO POWER DEVELOPMENT

Despite the many complexities involved in private small hydro power development, and the costs associated with them, there remain several benefits to the ultimate user of the project. These include:

- Reduction of construction risk by leaving development details with experienced companies;

- Reduction of capital involvement (at Moses Inlet, the Forestry company will pay about 15% less than the projected diesel cost each year and will be able to buy out the project for a one year payback in year 10. Their capital input is limited to facilities which they would require for a diesel-only power plant, and they obtained a new water supply and fire protection from the penstock);

- Reduction of maintenance risk by ensuring that experienced personnel are involved in monitoring maintenance activities;

The transfer of development details to a specialist company also leaves the personnel of the beneficiary (in the case of Moses Inlet, a forestry company) with more time at their own jobs, taking care of their companies' primary business activities.

Glenn S. McDonnell
Civil Engineer - Water Resources

Glenn McDonnell has nearly 10 years experience in civil engineering, the last 6 years largely concerned with small hydro power developments and resource studies in British Columbia. All of the time spent on small hydro power has been with Sigma Engineering Ltd., whose principals had been involved in some of the major hydroelectric developments in Western Canada in the 1960's. This early experience became the basis for the company's involvement in small hydro in the late 1970's and Glenn McDonnell became involved in the first project

constructed by the company providing design reviews, project coordination, and assistance with commissioning covering field work and technical details. Subsequently the company's work in small hydro has included small hydro studies for the Federal and Provincial Governments and BC Hydro, private feasibility studies and construction of two more projects, the last one Moses Inlet.

SMALL HYDRO ECONOMICS

SMALL HYDRO ECONOMICS IN ONTARIO
THE PROJECT PERSPECTIVE

Terry Burrell
Victor and Burrell, Research and Consulting
Toronto, Ontario

INTRODUCTION

Over the past 5 years, there has been a marked increased interest in small hydro development in Ontario. Concern about developing indigenous energy resources, coupled with significant government program stimulation has resulted in considerable small hydro activity. Several feasibility studies have been undertaken and a number of small hydro projects have been initiated and completed.

It is clear that the economic attractiveness of small hydro projects will be a fundamental determinant of how much of the small hydro's technical potential will be implemented. This paper examines the economics of small hydro in Ontario by:

- Examining the economic criteria which prospective proponents may use in determining the economic attractiveness of small hydro projects.
- Outlining the revenue prospects for small hydro for different cases - internal consumption, sales to the grid and so on.
- Assessing the maximum allowable capital cost for small hydro projects in Ontario under a variety of assumptions about economic attractiveness criteria, revenues, proponent type, and tax treatment. (Maximum allowable capital cost is the cost under which the complete project cost should come, in order to satisfy the specified economic viability criterion.)
- Comparing the capital costs of projects to date in Ontario with the maximum allowable cost
- Drawing conclusions about the factors most likely to have a positive impact on future small hydro economic viability in Ontario.

CRITERIA FOR ECONOMIC PERFORMANCE

Private developers, local utilities and Ontario Hydro (which is not normally thought of in this way) are all candidate proponents for small hydro in Ontario. What economic performance criteria are they likely to use in determining whether a project is sufficiently economically attractive to merit development?

- Ontario Hydro. As Amir Shalaby notes in his paper, Ontario Hydro assesses the benefits of small hydro in terms of the alternative generation costs saved by the utility. As with other capital projects, Hydro will use its corporate discount rate to evaluate small hydro. Given the rate of inflation assumed by the Ontario Ministry of Energy to the end of the century (about 6%), Hydro's corporate discount rate is likely to fall in the 10% to 13% range.

- Local utilities. The criterion used to evaluate small hydro differ from Board to Board. The importance of the project, the entrepreneurial spirit of the Board and the Board's knowledge of, interest in, and commitment to the idea of having locally based generation capacity will all have an influence.

- Many utilities will seek a rate of return comfortably above the cost of financing the project (currently about 11%). In the current economic climate rates of return of 15% to 20% on total capital may be typical. However, utilities placing a high value on local generation capability may be willing to accept a rate closer to 11%.

- Private Sector. Tax concerns are central to private sector proponents. Two groups of investors can be distinguished. Corporate investors are probably looking for after-tax returns in the vicinity of 20% to 25% on equity in the current economic climate. Individual private investors are likely to be satisfied with something closer to 15% after tax, perhaps less in some cases.

All of these criteria are rough estimates, used for indicative purposes only. Specific cases will fall outside these ranges. Of course, a change in the economic climate will shift the criteria. For instance, a rise in expected inflation will increase return requirements.

IMPLICATIONS FOR CAPITAL COST TARGETS

Small hydro projects may have an economic life of 30 years or more. However, 20 years (or less) is a common time perspective used by prospective proponents especially those in the private sector. With the exception of some sensitivity analysis of the results for 30 and 40 year horizons, this paper has used the 20 year period. Costs and revenues are expressed in 1985 dollars.

PROJECT REVENUES

The revenue generated from the sale of each kwh depends upon the value of what it is replacing. Typical rates for grid applications are indicated below:

TABLE 1

SELECTED ELECTRICITY RATES

Ontario Hydro Buv Back Rate. (Capacity Factors 65% or more)	3.45 cents/kwh
Ontario Hydro Buy Back Rate. (Capacity Factors less than 65%)	2.45 cents/kwh
Residential Rate (Toronto)	4.8 cents/kwh
Charge to Municipal Utilities (Approximate Average)	3.5 cents/kwh

For off-grid applications, the values are much higher - depending on delivered fuel costs, kwh costs can be 15 cents and more.

Since the project will typically be generating revenue for at least 20 years, future prices for electricity will have an important impact on the value of the project. The Ministry of Energy has generated three projections for electricity prices over the period to the end of the century. They are shown in nominal terms in Figure 1. They are for residential rates in Toronto; however, the growth pattern can be assumed to apply to all on-grid Ontario applications.

As Figure 1 indicates, the Ministry of Energy's forecasts assumed the electricity price will increase from a little under 5 cents in 1985 to 10, 11 and 12 cents in the low, medium and high cases respectively in the year 2000. In real terms (removing the effects of inflation), this constitutes a decline of about 12% by the year 2000 for the low case. The medium case embodies a slight real decline and the high case a slight real increase. The medium case has been assumed in the analysis below.* For all years after 2000, it is assumed that prices increase at the rate of inflation.

---

* The projections for fuel used in diesel applications show a much wider variation, reflecting current uncertainties. By the year 2000 real fuel prices are projected to decrease by 20% in the low case, by 2% in the medium case and increase by 18% in the high case.

CAPITAL COST IMPLICATIONS

To use these revenue values in deriving allowable capital costs.

- estimate annual revenue values which are net of operating, maintenance and administration costs (OM&A)

- specify assumptions about rate of return criteria, capacity factors, and tax treatment.

ANNUAL OM&A COSTS

A review of projects funded under the Canada/Ontario Conservation and Renewable Energy Demonstration Program was recently conducted for the Ministry of Energy by the SNC Group.** For the seven small hydro projects examined, the annual OM&A cost ranged between .1 and .6 cents per kilowatt hour. A small hydro costing model developed for the U.S. Department of Energy, suggests a figure of 3% of total capital cost per year.*** This would put the cost in the vicinity of .6 cents or higher for the range of capital costs in the Ontario projects.

The revenue per kilowatt hour specified in the analysis which follows should be interpreted as revenue net of OM&A costs. For example, a 1985 net value of 3 cents per kilowatt hour is equal to Ontario Hydro's buy-back rate, less about .4 cents OM&A cost.

ANNUAL CAPACITY FACTOR

Sizing of the small hydro installation to stream flow is primarily a matter of economics. It is a trade-off between the cost of an extra KW of capacity and the value of that KW in revenue terms. The lower the marginal cost of additional kilowatts and the higher the present value of the kilowatt hours generated by the additional capacity, the more it will make economic sense to move to select a lower capacity factor.

Thus, capacity factor is proponent and site specific. Projects wishing to receive the full 3.45 cents/kwh for all output from Ontario Hydro for will have to meet capacity factors of 65% or more. The Ontario projects reviewed by SNC had capacity factors in the 60% to 95% range. The weighted average was approximately 65%. An average 70% capacity factor has been assumed for the analysis.

** Small Hydro Technology Assessment and Monitoring Project, SNC Inc., December, 1985.

*** Broadus, Charles, R. Hydropower Computerized Reconaissance Package Version 3.0, EG&G Services, Inc., June 1985.

NON-TAX PAYING PROPONENTS

IMPACTS OF VARIATIONS IN RETURN CRITERIA AND REVENUE

Ontario Hydro and local utilities are two prospective proponents who pay no tax on income. Figure 2 shows estimates of allowable capital costs for internal rates of return between 5% and 25%, assuming net revenues of 2, 3 and 4 cents per kwh. For 3 cents a kilowatt hour the maximum allowable capital cost is about $2,300 at an 11% rate of return, $1,700 at 15% return and $1,300 at 19% return. Changing the net revenue to 4 cents/kwh raises these values over 30% to about $3,100, $2,300 and $1,800, respectively.

THE IMPACTS OF CAPACITY FACTOR

The effect of changing the capacity factor is illustrated in Figure 3 at 3 cents per kwh. An increase in capacity factor from 70% to 90% raises the allowable cost by about 30%: for example, at a 90% capacity factor a non-tax paying proponent could afford a capital cost of about $2200 and achieve a 15% rate of return.

TAX PAYING PROPONENTS

TAXATION CASE 1

Figure 4 presents results for a tax paying proponent receiving net revenues of 3 and 4 cents/kwh.

Taxes are assumed to be 46%, with equity at 100%. It is assumed that all of the capital costs are eligible for Class 34 depreciation. This is a fast write-off capital cost allowance (25%, 50%, 25% straight-line depreciation over three years) which currently applies to virtually all of the equipment and civil costs for a project using an existing dam. Access roads, some distribution costs, transmission and dam construction costs are all not eligible for Class 34.

Thus, the assumption that all of the costs are eligible for Class 34 is relevant for the currently typical case of a project which uses an existing dam and has no significant expenditures on distribution, transmission and access roads.

The results in Figure 4 also assume that the capital cost allowance (CCA) can be used to offset taxes on income outside the project. This is the assumption which separates Taxation Case 1 from Taxation Case 2. Taxation Case 1 assumes that CCA can be fully utilized, even if the project does not generate sufficient taxable income in the first three years to write off the capital cost. For example, corporate investors with taxable income in other divisions would be able to do take advantage of this.

The maximum allowable capital cost is lower than for the non-tax paying case. For example, at a 15% after tax return, the capital cost is about $1,350 at 3 cents/kwh and $1,800 at 4 cents/kwh. Thus this rate of return, a non-tax paying investor can afford to pay about 25% more in capital cost.

TAXATION CASE 2

Taxation case 2 assumes that the CCA is written off against project income only. Figures 5 displays the results, at 3 cents/kWh, and 100% equity financing.

THE IMPACT OF INCREASED DEBT FINANCING

The effect of increasing the amount of debt financing is shown in Figure 6. It demonstrates the impact of increasing the debt portion from 0 to 25% and then to 50% for Taxation Case 1. The interest rate on debt is assumed to be 11%. At a 15% required return on equity and 3 cents per kilowatt hour, 25% debt increases the allowable capital cost by about 20% ($1,400 to $1,700). A move to 50% debt financing increases the allowable cost dramatically to over $2200. Figure 6 shows that this impact increases with the rate of return.

Although not illustrated in Figure 6, the leverage effects are much greater for Taxation Case 1 than Taxation Case 2. Increasing debt financing raises allowable capital cost for Case 2 as well, but not by as much. Case 1's advantage over Case 2 doubles to about 20% of capital cost when debt financing of 25% is introduced and to over 30% of capital cost when the project is 50% debt financed.

THE IMPACT OF CLASS 34 REMOVAL

Currently, there is some uncertainty over the future of Class 34. What would be the impact of removing it?

If Class 34 were eliminated, the majority of small hydro equipment would fall into Class 2 (6% declining balance) under current provisions. Figure 7 shows the impact of removing Class 34 for Taxation Cases 1 and 2, assuming a 15% rate of return, 25% equity, 11% cost of debt financing, and 3 cents per kilowatt hour net revenue.

As Figure 7 shows, the outcome is dramatic for Taxation Case 1 (use of CCA on income outside the project). Class 34 results in a capital cost which is about 30% higher than it would be if the capital cost were not eligible for Class 34 treatment.

The impact on Taxation Case 2 is significant but on a smaller scale. Class 34 permits an increase in capital cost of about 15%.

THE IMPACT OF OTHER VARIATIONS

TIME HORIZON

The effect of extending the evaluation horizon beyond 20 years depends primarily on the required rate of return. The higher the rate, the smaller the impact on allowable capital cost.

The non-tax paying proponent is the most relevant to consider. Table 3 illustrates the effect of extending the time horizon to 30 and 40 years for three rates of return. As the Table shows, the maximum impact is a 40% increase in allowable capital cost for a 40 year horizon at 11% return rate.

TABLE 3

THE IMPACT OF INCREASING THE ECONOMIC HORIZON
INCREASE IN ALLOWABLE CAPITAL COST OVER 20-YEAR HORIZON

Allowable Capital Cost % Increase Over 20-Year Horizon	Rate of Return 11%	15%	19%
30-Year Horizon	25%	14%	7%
40-Year Horizon	40%	20%	10%

ELECTRICITY PRICE GROWTH

For a 15% rate of return, the effect of assuming the Ministry's alternative electricity price scenarios to the end of the century* results in a variation in allowable capital costs of approximately 4% around the medium scenario. That is, allowable capital cost would increase by about 4% under the high scenario and decrease by about the same amount under the low scenario. This does not change appreciably with the rate of return.

---

* and the rate of general price inflation thereafter.

THE RANGE OF ALLOWABLE CAPITAL COSTS

In the current context, allowable capital cost ranges of $1,300 to $2,300 per KW for non-tax paying proponents and $1,000 to $1,300 for tax paying private sector proponents may be typically required. This assumes:

- a capacity factor of 70%
- rates of return between 11% and 19% (20 year horizon) for non-tax paying proponents
- rates of return between 15% for Taxation Case 2 (100% equity) and 25% for Taxation Case 1 (75% equity)
- net revenues of 3 cents per kwh (roughly corresponding to current buy-back rates)

An increase in buy back rate by 1 cent would change this from a $1,000-$2,300 range to a $1,300 - $3,100 range.

What implications do these figures have for small hydro development in Ontario?

ONTARIO PROJECT COSTS

Lack of data makes it difficult to draw any firm conclusions about the megawattage of economically attractive small hydro sites in Ontario. However, some inferences can be made from the projects which have been implemented to date and feasibility study information.

All of the seven sites investigated by SNC fall within the target capital cost range - all were under $2,300.

With the allowable capital costs specified above, only sites with existing dams will be of interest for grid applications. Gulliver and Dotan*, drawing on the work of Gordon and Penman (1979), have developed a procedure for estimating the costs of small hydro projects based on KW capacity and net head. They estimated equipment costs as a function of net head and kW capacity using a regression equation based on extensive U.S. data. They then derived total capital costs from the equipment costs from three typical project cases.

- The existing powerhouse requires minimal modification. Equipment cost estimates are multiplied by 1.5 to give total capital cost.

---

* See John Gulliver and Avry Dotan, Cost Estimates for Hydropower at Existing Dams, Journal of Energy Engineering, September, 1984.

- The existing powerhouse requires major modification. Equipment costs are multiplied by a factor ranging between 2 and 3.

- There is no existing powerhouse; a new powerhouse must be contructed. Equipment costs are multiplied by 3 for projects 5 MW and greater; for sites below 5MW the factor is greater than 3, and increases as installed capacity decreases.

Sufficient data is lacking to derive a relationship giving significant confidence for the Ontario setting. However, a rough attempt was made to apply the same method using Ontario data. Two sets of data were used to derive regression equations.

Data is inadequate to develop comparably reliable estimating equations for the Ontario setting. However, for illustrative purposes only, the Gulliver and Dotan approach was applied to the limited data available for the province. First, regression analysis was applied to two sets of Ontario cost data, to develop two separate estimates of equipment costs for a range of assumptions about net head and KW capacity. Two alternative sets of capital cost estimates were then derived for Gulliver and Dotan's 3 cases by applying the factors described above the equipment cost estimates. It should be emphasized that the capital cost estimates have been derived for illustrative purposes only.

The first data set was manufacturer estimates of equipment costs presented in SNC (1985). This resulted in Equation 1 which was used to produce Table 4 and Table 5 for the "Existing Powerhouse with Minimal Repair" and "No Existing Powerhouse" cases. The reader will note in Table 4 the estimates vary considerably with head but almost not at all in KW capacity. The lack of economies of scale is surprising. It does not correspond with the Gulliver and Dotan results, nor does it agree with data available on Ontario projects.

The second set of data was assembled by the Ministry of Energy on more than 25 completed projects and feasibility studies. Equation 2, based on this data was used to produce Tables 6, 7 and 8. It should probably be preferred to Equation 1 because it displays the expected characteristics. However, it is based on limited information and is not to be relied upon for feasibility estimates.

The reader will note that many of the costs in the minimal repair scenario fall within the range of $1,000 to $2,300 (see Table 6). However, few in the "Major Repair" category and none in the "No Existing Powerhouse" (Tables 7 and 8) do. However, it should be observed that a large number of projects in Table 7 and many in Table 8 are $3,100 or less. This puts them in the allowable capital cost range generated by increasing the buy-back rate by 1 cent/kWh.

* See John Gulliver and Avry Dotan, Cost Estimates for Hydropower at Existing Dams, Journal of Energy Engineering, September, 1984.

OFF-GRID APPLICATIONS

The high costs of diesel generation raise the allowable capital cost several times over - to $15,000 per KW and more, for example. Thus the possibility exists for developing sites with much higher costs - sites with dams and transmission requirements.

The key is to find projects with a suitable combination of promixmity to load and adequate load size.

CONCLUSIONS

Small hydro economics in Ontario are significantly influenced by a wide range of factors including value of electricity displaced, buy-back policies, tax treatment, the general economic climate and the availability of debt funding.

From a policy perspective the most important elements are buy back policy and tax treatment. Increased rates from Ontario Hydro have significantly improved the picture for small hydro. An additional increase would help even more; it may result in a large number of additional projects becoming economically viable. On the other side, the elimination of Class 34 could seriously hamper private development of small hydro projects in Ontario.

TABLE 4

TOTAL CAPITAL COST ESTIMATE
(1985 $ Per KW)

EQUATION # 1

EXISTING POWERHOUSE WITH MINIMAL REPAIR
Site Factor:
1.5

Head (Metres)	Kilowatt Capacity 100	1,000	5,000	10,000
3.0	$2,241	$2,254	$2,263	$2,267
6.0	$1,695	$1,704	$1,711	$1,714
9.0	$1,439	$1,447	$1,453	$1,456
12.0	$1,281	$1,289	$1,294	$1,296
15.0	$1,171	$1,178	$1,183	$1,185
18.0	$1,088	$1,094	$1,099	$1,101
21.0	$1,023	$1,028	$1,033	$1,034
24.0	$969	$975	$979	$980
27.0	$924	$929	$933	$935
30.0	$886	$891	$894	$896

TABLE 5

TOTAL CAPITAL COST ESTIMATE
(1985 $ Per KW)

EQUATION # 1

NO EXISTING POWERHOUSE

Head (Metres)	Kilowatt Capacity 100	1,000	5,000	10,000
3.0	$7,684	$5,599	$4,526	$4,534
6.0	$5,810	$4,234	$3,423	$3,428
9.0	$4,934	$3,595	$2,906	$2,911
12.0	$4,394	$3,201	$2,588	$2,593
15.0	$4,016	$2,926	$2,365	$2,369
18.0	$3,731	$2,718	$2,198	$2,202
21.0	$3,506	$2,555	$2,065	$2,069
24.0	$3,322	$2,421	$1,957	$1,960
27.0	$3,168	$2,308	$1,866	$1,869
30.0	$3,037	$2,212	$1,789	$1,792

TABLE 6

TOTAL CAPITAL COST ESTIMATE
(1985 $ Per KW)

EQUATION # 2

EXISTING POWERHOUSE WITH MINIMAL REPAIR
Site Factor:
1.5

Head (Metres)	Kilowatt Capacity			
	100	1,000	5,000	10,000
3.0	$2,835	$2,303	$1,991	$1,870
6.0	$2,434	$1,977	$1,709	$1,605
9.0	$2,227	$1,808	$1,563	$1,468
12.0	$2,090	$1,697	$1,467	$1,378
15.0	$1,990	$1,616	$1,397	$1,312
18.0	$1,912	$1,552	$1,342	$1,261
21.0	$1,848	$1,501	$1,298	$1,219
24.0	$1,794	$1,457	$1,260	$1,183
27.0	$1,749	$1,420	$1,228	$1,153
30.0	$1,709	$1,387	$1,200	$1,127

TABLE 7

TOTAL CAPITAL COST ESTIMATE
(1985 $ Per KW)

EQUATION # 2

EXISTING POWERHOUSE WITH MAJOR REPAIR
Site Factor:
2.75

Head (Metres)	Kilowatt Capacity			
	100	1,000	5,000	10,000
3.0	$5,198	$4,221	$3,650	$3,428
6.0	$4,463	$3,624	$3,134	$2,943
9.0	$4,082	$3,315	$2,866	$2,692
12.0	$3,832	$3,112	$2,690	$2,527
15.0	$3,648	$2,963	$2,562	$2,406
18.0	$3,505	$2,846	$2,461	$2,311
21.0	$3,388	$2,751	$2,379	$2,234
24.0	$3,290	$2,672	$2,310	$2,170
27.0	$3,206	$2,603	$2,251	$2,114
30.0	$3,132	$2,544	$2,199	$2,066

TABLE 8

TOTAL CAPITAL COST ESTIMATE
(1985 $ Per KW)

EQUATION # 2

NO EXISTING POWERHOUSE

Head (Metres)	Kilowatt Capacity			
	100	1,000	5,000	10,000
3.0	$9,722	$5,719	$3,982	$3,740
6.0	$8,347	$4,910	$3,418	$3,211
9.0	$7,635	$4,491	$3,127	$2,937
12.0	$7,166	$4,216	$2,935	$2,757
15.0	$6,823	$4,014	$2,794	$2,625
18.0	$6,555	$3,856	$2,685	$2,521
21.0	$6,336	$3,728	$2,595	$2,437
24.0	$6,153	$3,620	$2,520	$2,367
27.0	$5,995	$3,527	$2,455	$2,306
30.0	$5,858	$3,446	$2,399	$2,253

FIGURE 1

Forecast Growth in Electricity Prices

Ministry of Energy, 3 Scenarios

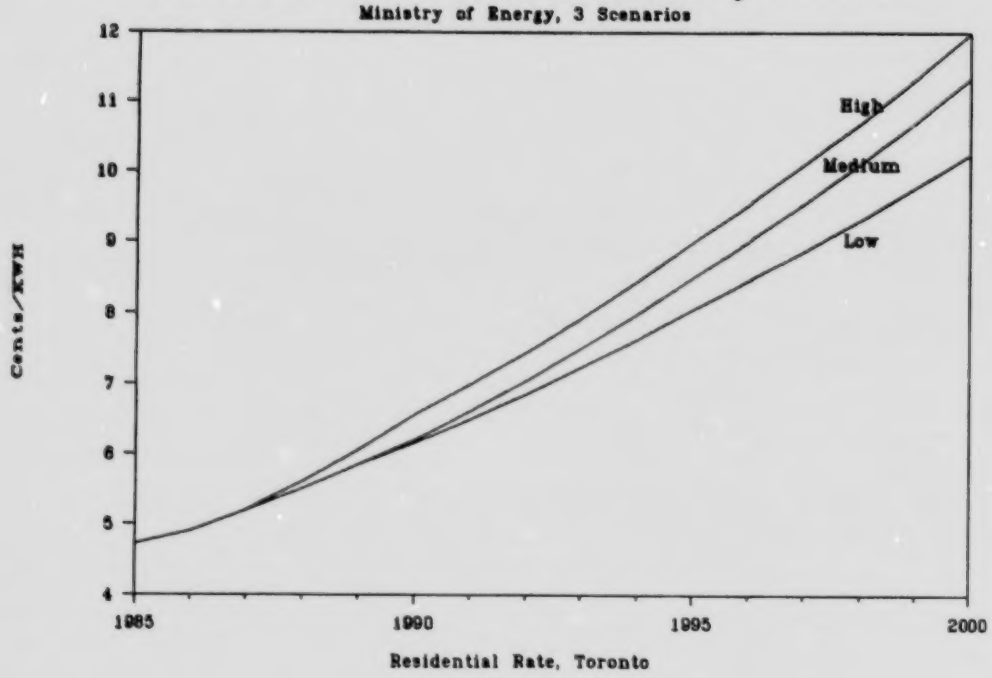


FIGURE 2

Allowable Capital Cost

Non tax-paying Proponent

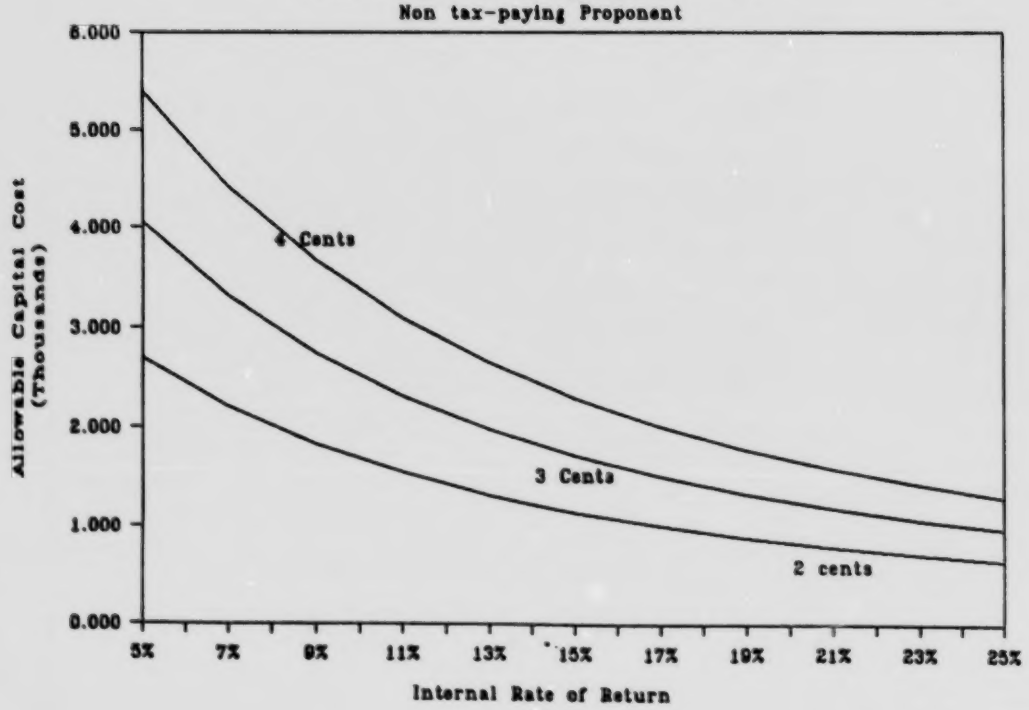


FIGURE 3

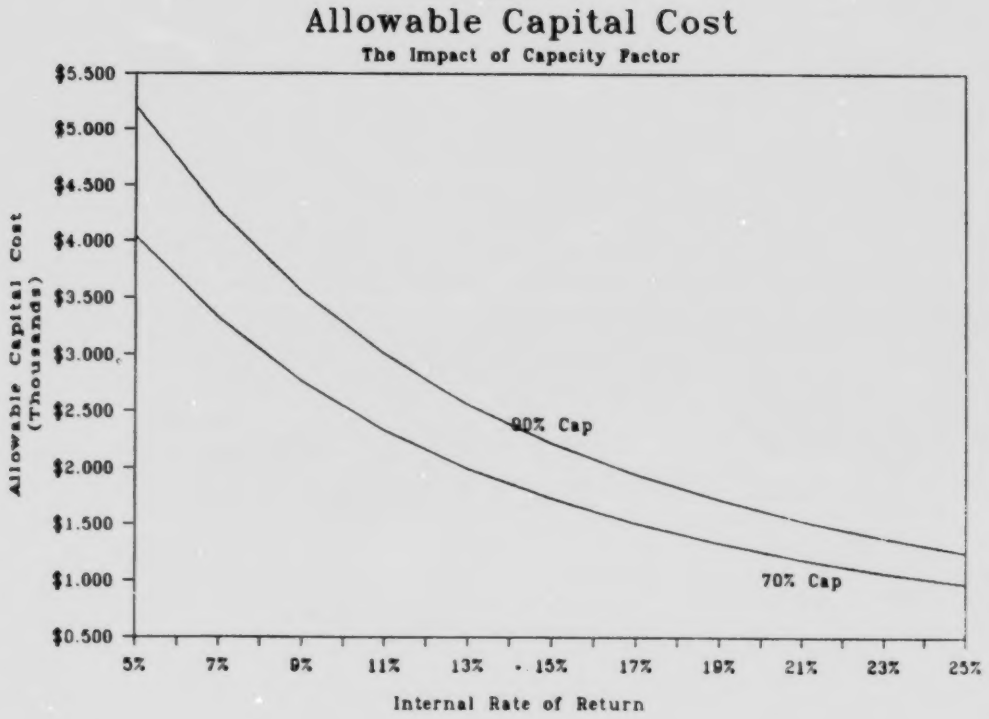


FIGURE 4

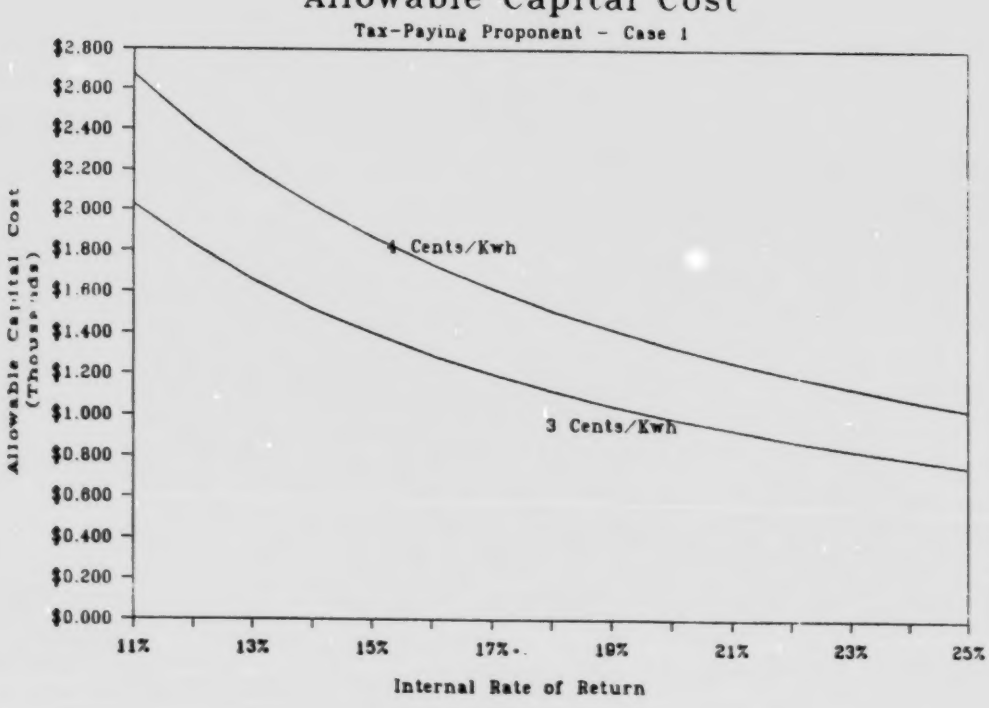


FIGURE 5

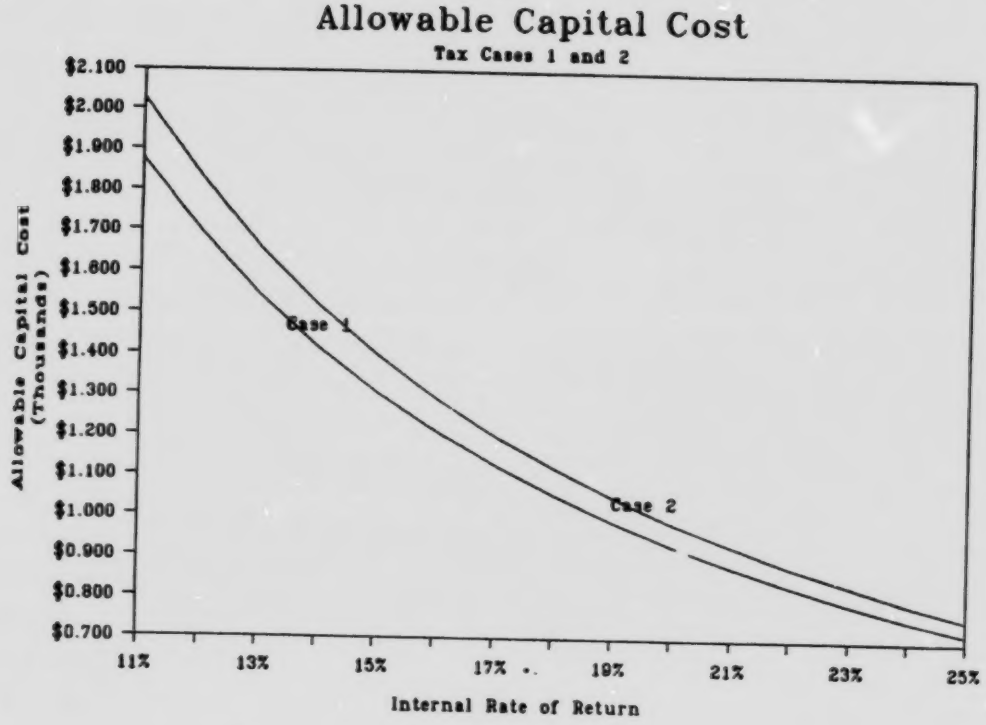


FIGURE 6

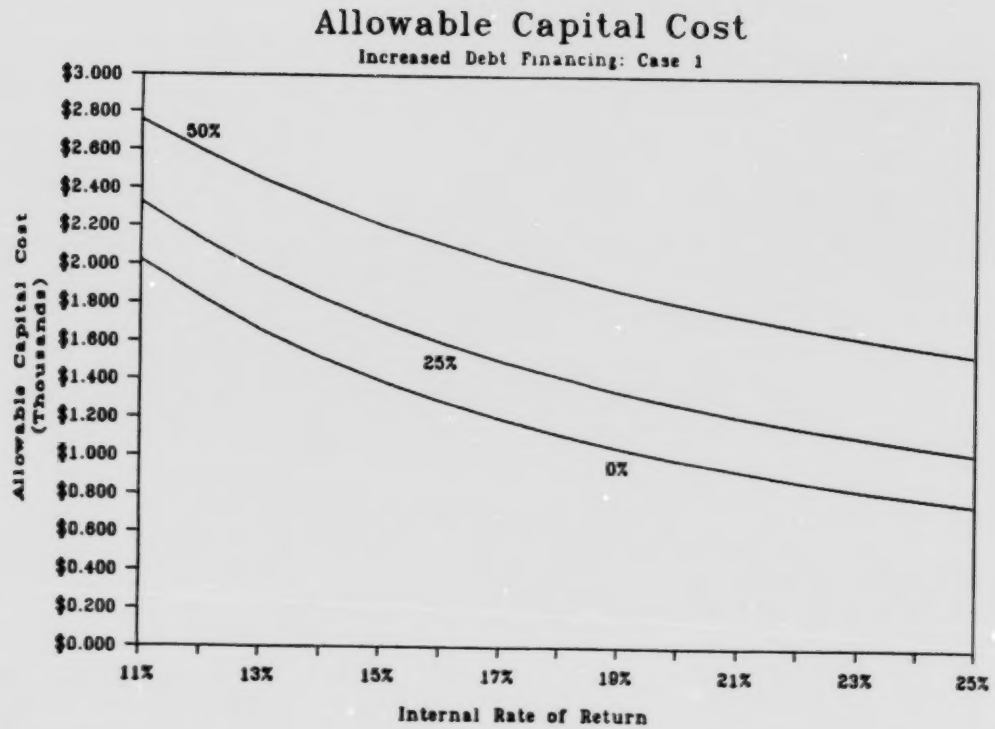
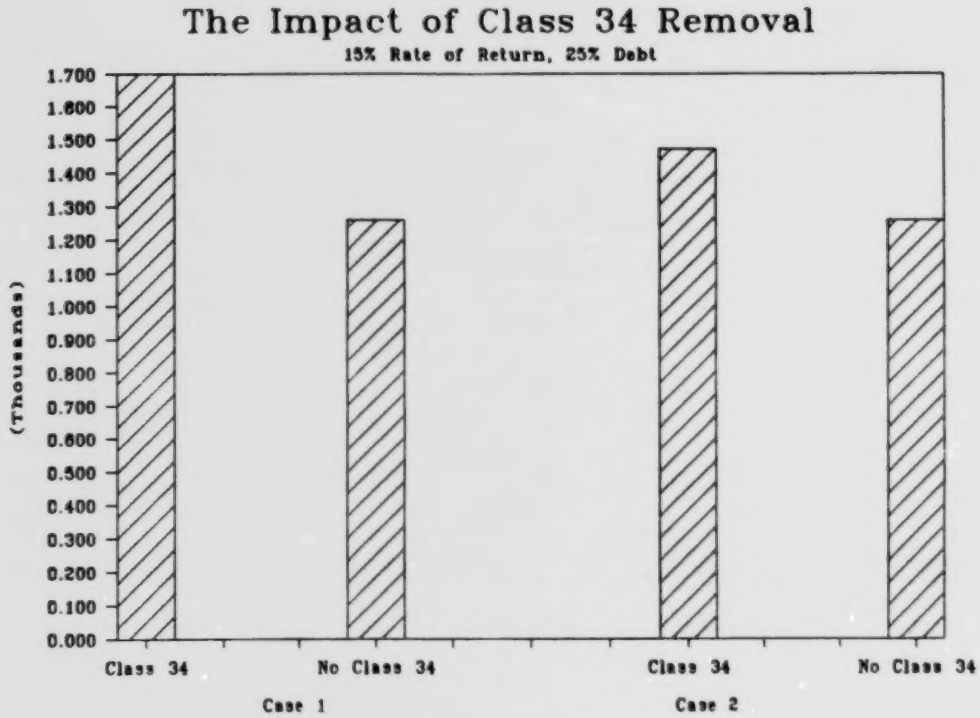


FIGURE 7


The Impact of Class 34 Removal
15% Rate of Return, 25% Debt
(Thousands)
1.700
1.600
1.500
1.400
1.300
1.200
1.100
1.000
0.900
0.800
0.700
0.600
0.500
0.400
0.300
0.200
0.100
0.000
Class 34
No Class 34
Class 34
No Class 34
Case 1
Case 2

PRIVATE POWER PRODUCTION IN ONTARIO: ONTARIO HYDRO'S PERSPECTIVE

Amir Shalaby
System Planning Division
Ontario Hydro

1.0 INTRODUCTION AND OUTLINE

This paper is the second part of this session of Small Hydro 86" Conference about Economics. I am pleased to be invited to present the utility perspective.

This paper discusses the issues that shape the relationship between Ontario Hydro and private power producers in the Province. By the end of this paper, I hope to have walked you through our business to give you an idea about the characteristics of Ontario's demand for electricity, how we plan and operate our system to meet the Province's needs, and finally, how a private producer fits in this picture from our perspective.

To do so, here is a road map for what I plan to take you through:

1. Identify the areas of impact on the utility as a result of private power production.

2. Review Ontario Hydro's policies re private producers.

3. Explain the basis for determining Ontario Hydro's purchase rates. To do this, I will briefly introduce you to the concept of avoided costs. To develop that concept we will need a quick review of:

   - The characteristics of the province's demand for electricity: How it varies hourly, daily and seasonally.

   - How this demand is served: from what generation sources, now and in the future.

   - The cost of meeting the demand for electricity: on average and incrementally.

   - Which of these costs can be avoided due to private electricity production.

4. Compare Ontario Hydro's purchase rates to:

- Ontario Hydro's avoided costs.
- purchase rates paid by other Canadian utilities.
- purchase rates paid by comparable U.S. utilities.
- Darlington's costs.

2.0 IMPACT OF PRIVATE PRODUCERS ON THE UTILITY

The integration of private producers into the operation of the utility has a number of significant impacts that must be carefully considered by the utility when setting policies. The following is a listing of some of these issues, they will be addressed further as the discussion progresses:

- Public and employee safety.
- Secure operation of the integrated system.
- Reliability of supply to customers.
- Cost of electricity to customers, both in the short term and in the long term.
- Assurance of long-term secure supply of energy.
- Equity amongst customers.

3.0 ONTARIO HYDRO'S POLICIES RE: PRIVATE GENERATION

Ontario Hydro encourages the development of private generation that is beneficial to the people of Ontario. To support this objective, Ontario Hydro:

- Provides some technical assistance.
- Interconnects with private generators.
- Provides standby power.
- Buys surplus electricity at rates that are fair.

To explain policies and service conditions to those interested in developing private generation, Ontario Hydro publishes two information items entitled "Parallel Generation Rates and Service Conditions" and "Parallel Generation Interconnection Requirements". The phone numbers of our Regional Marketing Managers who are the customer contacts are listed. The publications also explain a number of issues, including:

The Purchase Rate Schedule - Wheeling

Purchase Arrangements - Costs Borne by Parallel Generator

Metering - Technical Requirements

Procedure for Approval

Copies of these publications can be obtained from Hydro's Public Reference Centre and from the Regional offices.

Purchase rates, the rates Hydro pays a private generator for this production, are of interest to developers and also to concerned citizens and groups who are interested in this province's energy options.

The rates paid by Ontario Hydro in 1986 are summarized as follows:

Standard Rates	Optional Rates
3.45 cents/kW.h for high capacity factors	There are optional rates for:
2.45 cents/kW.h for low capacity factors	. Peak and off-peak hours . Summer and Winter . Energy & capacity

The complete rate schedule is attached as an appendix to this paper.

Because of the significance of purchase rates to small-scale hydro developers, I will explore the basis for setting these rates in some detail in the following section.

4.0 THE BASIS FOR DETERMINING PURCHASE RATES

The purchase rates reflect Ontario Hydro's long-term avoided costs. Avoided cost is a term that was introduced in the U.S. These costs are calculated to reflect how much is saved by a utility if it purchases electricity from cogenerators and small power producers.

Ontario Hydro's purchase rates reflect the long-term avoided costs. Let's take a minute to reflect on the historical costs of electricity in Ontario. Residential electricity rates have been stable over the past thirty years at around 4-5 cents/kW.h when expressed in dollars of 1985. These rates are projected to decline in real terms over the next 15 years. In general, fuel costs are about all a utility will save in the short term when a small power producer sells it electricity. This is because, except in special circumstances, the transmission, distribution and such of the overhead is not avoidable. Over the past two decades, fuel costs have contributed about half the total cost of service reflected in the retail rates. If a private generator can supply peak demand for most hours of the year. then this could result, in the longer terms in deferring the need for generating capacity.

It is worth emphasizing that in the short term, incremental energy is valued at 2.1 cents/kW.h, while the purchase rates are 2.45 to 3.45 cents/kW.h. Therefore, the purchase rates

could be up to 150% of the short-term avoided cost. They are designed to reflect the Corporation's policy in encouraging private generation and development of efficient new technologies.

The rates are higher for high capacity factor parallel generation to recognize the dependable contribution to both capacity and energy. The optional energy rates recognize the higher value of energy during peak hours and during winter. I will explore later in Section 5.0 why is it that electricity made available to Hydro at peak hours and winter hours is more valuable.

5.0 AVOIDED COSTS

Now that we focused on the concept of avoided costs with its significance in determining purchase rates, let's look at how it is determined.

To get at avoided costs, I will follow a set of steps:

- Review the characteristics of our customers demand: hourly, daily, and seasonally.
- Show you how we use our installed facilites to serve our customers at least cost.
- Discuss what of the costs can be avoided if a private generator is added to the system.
- Introduce the idea of incremental demand and its impact on our resource allocation.
- Illustrate the cost of meeting customer demand, particularly incremental demand. Tie the incremental cost of servicing customers to purchase rates.

5.1 CHARACTERISTICS OF ONTARIO'S CUSTOMER DEMAND

Figures 1-4 show how Ontario Hydro sees the total demand for electricity by all of our customers. We call that total 'system' load.

Figure 1 is for a typical January day, and Figure 2 is for a typical July day.

In the winter, the system load picks up in the morning hours, encounters two peaks, one in the morning and another around 5-6 p.m., but you will notice that it stays approximately flat at that levelI for about ten hours. Looking at these two graphs, you can see that only the nighttime hours are significantly lower in demand level, for that reason we call the hours 7 a.m.-11 p.m. "peak hours" and the remaining 8 hours "off-peak" hours.

Next, Figure 3 shows the monthly variations in peaks. It shows that the winter months are the highest in demand and the spring and fall the lowest. But it also shows that the summer peaks are still significant at around 80% or so of the winter peaks.

A figure called the 'load factor' is something utilities use to capture these load characteristics. The load factor is the average demand divided by the peak demand. For a winter day, for example, the load factor is about 85-90%, meaning the peak is only 10-15% above the average. On an annual basis, the load factor in Ontario is around 68%, this means that on average, customers demand 68% of what they demand on the Peak Period. Ontario's load has a relatively high load factor when compared to other jurisdictions and countries which are typically in the 50% load factor zone. The higher the load factor, the more utilized the facilities built to serve the load and hence the more economic the service becomes. The average cost of electricity declines as the load factor increases as long as the marginal cost of production is lower than the average cost.

Finally, I want to discuss Figure 4 which is what we call a 'load duration curve'. It is a curve showing all the hourly demands, there are 8760 of those points/year, sorted in a descending order. On the left is the highest hourly demand or peak, usually in January or December, and from there as you move to the right the lower loads are shown, at the very right is the least load in an hour, usually a cool weekend night hour in the summer.

The way to interpret the percentages on the x-axis is as follows: on the left, 0% means that at no time the load in 1984 was higher than 18896 MW, midway we can see that 50% of the time the load was higher than 70% of the peak, around 13200 MW. At the very right where the 100% is we can see that at no time was load lower than 40% of the peak, or about 7600 MW.

This load duration curve is quite useful to utility operators and planners as I will show in the next section.

5.2 HOW ONTARIO HYDRO MEETS CUSTOMER DEMAND

To meet our customers' demand reliably and at lowest cost is not a straight forward proposition given its varying nature and given the different resources available such as: coal, oil, water, uranium, purchases from neighbouring utilities, and private generation.

The principle is simple. Use the cheapest resources first until they are all used up, and then move on to the more expensive ones, and so on. There are often considerations that alter this simple principle, such as transmission limitations, maintenance scheduling and other operating considerations. For this purpose, a utility classifies its resources into what they call "base loaded" resources, those are the cheapest to run and are run flat out year-round. The other type is "peaking"

resources, these are either limited on the energy they can provide or are expensive to run and are used only when absolutely necessary. In Ontario nuclear and hydraulic generation with lots of water year-round is base loaded, oil and gas as well as hydraulic with limited amounts of water that need damming and storage are used for peaking. There is also an intermediate category in Ontario and that is coal and electricity purchases from other provinces.

Figure 5 illustrates how these generation types are used to meet the daily demands in January.

The picture gets more interesting when we gather all the hourly demands (the load duration curve) and show how the generation is used year-round to meet the demand. Figure 6 shows, conceptually, the utilization of base loaded, intermediate and peaking resources to meet demands year- round.

5.3 COSTS THAT CAN BE AVOIDED DUE TO PRIVATE GENERATION

A private generator can provide electricity to displace whatever fuel Ontario Hydro is using at the most expensive generation source. That is, if a small hydro comes on-line at 6 p.m. on a winter night, it can displace coal, peaking hydraulic, or later in the 1990's, even oil and gas. If it comes on at midnight in the summer, it is unlikely to displace coal, but rather run-of-the-river hydraulic energy or nuclear from our base loaded stations. If private generation is developed in a large-enough magnitude in areas that need transmission reinforcement, then it could well defer the need for transmission and distribution facilities. The recent experiences in Ontario, however, show small scattered developments of private generation that do not generally reduce the requirements for high-voltage bulk transmission and regional delivery facilities such as transformer stations. For this reason, most of the value of private generation to a wholesaler like Ontario Hydro is in saving fuel in the short term, and if enough reliable generation comes on-line, then it presents the utility with an opportunity to defer building new capacity in the long term.

5.4 INCREMENTAL DEMANDS

I want to now move a step further with the load duration curve to get to the fuel and hence short-term cost savings due to private generation. An economic analysis of this type calls for an incremental analysis: meaning analysing the impact of one more or less MW of peak demand or one more or less MW.h of energy consumption.

Let's take Figure 6 and add a slice of additional peak demand. As Figure 7 shows, this additional slice will be met by mostly intermediate resources, coal and electricity purchases and at some short periods with peaking resources and for some short periods with base loaded resources.

If we then take that wiggly slice and straighten it up into a bar, as shown in Figure 8, we arrive at the fuel mix that will be necessary to meet an increase in demand or will be saved if a private producer supplies that MW year-round. The figure shows what we expect that fuel mix to be for the next number of years. Notice that it starts out in the early 1980's being mostly coal, then some base loaded nuclear and hydraulic start to come in the late 1980's, then oil comes in the 1990's. Figure 8 shows the fuel mix averaged over the entire year.

The picture is quite different at different times of the year and different seasons of the years. Figure 9 shows how dramatically the fuel mix changes with season, peak, off-peak and as time goes on into the late 1980's and the 1990's.

This is indeed a very informative figure and explains the rationale for higher purchase rates during peak periods, in the winter and demonstrates the higher value of economical resources into the future.

It is worth reminding you at this point that the fuel mix displayed on Figures 8 and 9 is that before electricty sales to the U.S. are made. As electricity is sold, the quantities of surplus nuclear and hydraulic is reduced significantly.

5.5 THE COST OF MEETING INCREMENTAL DEMAND

Now that we've come this far, there is only one remaining step to estimate the cost of meeting customer demand. This step involves multiplying the fuel mix in Figures 8 and 9 by the cost of these fuels.

Figure 10 shows what we expect fuels to cost for the next number of years. Figure 11 shows the same information if the effects of inflation are removed. Figure 11 shows that coal-generated energy is expected to decline on real terms, in the late 80's and early 90's and then get more expensive as measures to meet environmental regulations add to the cost of coal-generated electricity. Nuclear fuel costs are relatively stable in real terms and of course are a lot less than coal. The cost of residual oil is expected to increase slightly in real terms. Recent sharp declines on oil prices are thought by some to be of a transient nature. Even if the long-term view changes, the impact on Hydro's avoided cost is small because oil is not expected to be used much.

When we multiply these costs by the proportions in Figures 8 and 9, we get what we call 'incremental energy values'. These are shown in Figures 12 and 13. These are the end result of all the calculations and constitute one of two components in determining avoided costs. The other component is less significant until the late 1990's and that is incremental capacity values. The value of capacity is low in the 80's and early 90's because Ontario Hydro has sufficient generating

capacity. The value goes up in the late 90's because there will be a need for additional resources to maintain reliable service to customers.

The value of capacity, in the late 90's, has two main components: (1) The cost of advancing or delaying construction of generating facilities, and (2) to offset that cost there are savings because base loaded generation (nuclear, hydraulic) displaces the more expensive intermediate generation (coal), and coal in turn displaces oil and gas.

The summary of all of this indicates that in the 80's and early 90's, energy costs are declining and capacity is abundant on the system. The late 1990's, however, is the period when both capacity and energy increase in value.

5.6 RELATIONSHIP BETWEEN PURCHASE RATES AND AVOIDED COSTS

The avoided costs we just calculated are the starting point in determining purchase rates. There are "unquantifiable" benefits from small dispersed generation that led Hydro to decide to pay more than short-term avoided costs. This value, of small hydro for example, depends on the period considered and on the assumptions about the future. The assumptions about the future could raise or reduce the projected avoided costs, due to uncertainty in the main factors that go into it such as fuel costs, generation mix, customer demand level and shape.

The value of resources that are reliable and promise secure production for years into the future is higher than resources that are based on technologies that may not perform as expected or as long as expected.

When considering that the short-term marginal costs are about 2.1 cents/kW.h for energy and $10/kW.h/year for capacity, it becomes clear that the purchase rates paid by Hydro consider the resources value into the future. The purchase rates are significantly higher than short-term marginal costs to encourage projects that are appropriate for Ontario and benefit the people of the province.

6.0 COMPARISON OF ONTARIO HYDRO'S PURCHASE RATES TO OTHER UTILITIES AND TO THE COST OF NEW GENERATION

Now that we developed Hydro's avoided costs and purchase rates, I would like to relate these to a number of other facts. First to rates paid by other utilities, both in Canada and the U.S. Then compare them to the cost of electricity from new generating stations built by Ontario Hydro. The objective is to demonstrate that Hydro's purchase rates compare favorably with these yardsticks.

6.1 PURCHASE RATES PAID BY UTILITIES DEPEND ON THEIR OIL AND GAS BURN

Figure 14 is a plot of what U.S. utilities pay private producers as function of their oil and gas burn. It shows that the purchase rates offered by a utility increase as the percentage of oil and gas generation increases. This is because utilities that depend on high fuel costs have short-term avoided costs that are higher than those for coal, hydraulic or nuclear based utilities. The figure shows 1982 purchase rates for the U.S. These have generally been lowered since 1982. The marginal costs decreased because oil prices declined, and because private generation, electricity purchases or low cost base loaded generation brought into service displaced the expensive marginal plant on the utilities system. This means that if the 1985 data were plotted, it will show lower purchase rates across the board. For example, TVA lowered their 'all hours' rates from 3.44 cents/kW.h to 1.75 cents/kW.h. Pacific Power and Light lowered their rates from 3.3 cents/kW.h to 1.72 cents/kW.h.

If Ontario Hydro purchase rates are to be compared to U.S. utilities, the meaningful comparison is to those with little oil and gas burn.

It is perhaps worth mentioning here that private generation is encouraged by more than just high purchase rate. The high retail price of electricity, the low price for fuels and favorable tax incentives are more significant factors influencing investment decisions in cogeneration for example.

6.2 ONTARIO HYDRO PURCHASE RATES COMPARED TO OTHER CANADIAN UTILITIES

The following table shows that Ontario Hydro purchase rates exceed those offered by other coal and hydro based utilities in Canada. The utilities that are oil based (in Nova Scotia and Prince Edward Island) offer higher rates.

PURCHASE RATES - CANADIAN UTILITIES

(Source: Renewable Energy News June 1984)

B.C. Hydro	Will accept but not pay
TransAlta Utilities	1.6 cents/kW.h
Manitoba Hydro	Policy to be established
Hydro-Quebec	No policy
Newfoundland and Labrador Hydro	Will permit hook-up
Nova Scotia Power Corp.	6.2 cents/kW.h up to 10 kW 70% of retail rate up to 15 MW
Maritime Electric Commission	5.5 cents/kW.h
Ontario Hydro 1985 purchase rates	2.3-3.3 cents/kW.h (110% - 150% of short-term avoided costs)

6.3 ONTARIO HYDRO AND TVA PURCHASE RATES

Ontario Hydro rates compare favourably to similar U.S. utilities. TVA (Tennessee Valley Authority) is the largest 0.8. utility, often compared to Ontario Hydro because both are publicly owned and their development of energy resources (hydro, coal, nuclear) has followed a similar sequence.

The following table shows that the rates paid by TVA and by Ontario Hydro are comparable.

1985 PURCHASE RATES - TVA AND ONTARIO HYDRO

(In Canadian Cents/kW.h)

	TVA	Ontario Hydro
Peak	2.56 (Short Term) (1.83 U.S. cents) 3.39 (10-year contracts) (2.42 U.S. cents)	3.3
Off-Peak	2.45 (1.75 U.S. Cents)	2.3

6.4 ONTARIO HYDRO PURCHASE RATES COMPARED TO DARLINGTON'S TUEC

It is interesting to compare Hydro's purchase rates to the cost of electricity from new generating stations built by Hydro. This is relevant to the discussion because it could be argued that Hydro decides to build projects and purchase electricity from them on behalf of its customers. Darlington is still under construction and let's use its electricity cost for comparison. We define a quantity called the "Total Unit Energy Cost". This indicates all the costs associated with Darlington; construction, financing, operation, decommissioning, fuel, irradiated fuel storage. The Total Unit Energy Cost (TUEC) in nominal dollars is relatively stable over the life of the station. But because of inflation, the 'real' cost, or the cost expressed in $1985, declines.

Figure 15 shows that over a 20-year period, Darlington's TUEC (Total Unit Energy Cost) in $1985 declines from around 5 cents/kW.h to 2 cents/kW.h. It averages, over the period, about the same as the high capacity factor purchase rates. The cost of Darlington's energy is initially higher than the rates, but then dip below the purchase rate, as financing charges associated with this new asset decline.

Another way of looking at this is that the 'levelized cost of Darlington's electricity is the same as the purchase rates. This means that a parallel generator will receive the same payments for his electricity over a 20-year period as Darlington (TUEC). But another way, over the long term, the electricity customer will incur similar costs for Darlington as for parallel generated electricity.

This is a good point to discuss the issue of fairness and equity to all customers. It is in our customer's best interest to pay private generators rates that are similar to costs from other options and therefore do not increase the cost of electricity over the long term.

7.0 CONCLUSIONS

In Ontario, private generation that is beneficial to the people of Ontario is encouraged.

The institutional arrangements for private generation in Ontario are favorable to developers: they are not subject to rate hearings. Ontario Hydro interconnects with them and buys their electricity at significantly higher rates than short-term avoided costs to reflect the higher long-term avoided costs.

The purchase rates are significantly above short-term avoided cost to encourage developments of new, efficient, and appropriate technology for Ontario.

The rates exceed rates paid by coal and hydro-based Canadian utilities, and are comparable to rates paid by similar U.S. utilities such as the Tennessee Valley Authority (TVA).

The rates are also comparable to the total cost of electricity from new generating plants such as Darlington over the long term.

Private small-scale hydraulic generation is certainly a valuable resource to the utility because it is reliable and secure. Ontario Hydro expects to see a number of attractive sites developed or redeveloped over the next few years. In fact we are counting on the development of at least 20,000 kW of additional small-scale hydro in our resource plans.

APPENDIX

RATES FOR PURCHASE OF PARALLEL GENERATION IN ONTARIO

STANDARD ENERGY RATES

For capacity factors of 65% or greater - 3.45 cents per kW.h

For capacity factors below 65% - 2.45 cents per kW.h

Based on the rated kilowatt capacity of the generator or the measured kilowatts delivered in the month.

OPTIONAL RATES - FOR GENERATORS WITH CAPACITIES OF 250 KW OR GREATER

CAPACITY RATES

Winter	$7.30 Per kW* per month
Summer	$3.65 per kW* per month

* As measured during the peak period of the month. No capacity payment will be made in any month that the capacity factor is below 65%.

ENERGY RATES

Winter peak	2.92 cents per kW.h
Winter off-peak	2.33 cents per kW.h
Summer peak	2.56 cents per kW.h
Summer off-peak	1.60 cents Per kW.h

TIME OF USE

Winter	- October through March
Summer	- April through September
Peak	- 7 a.m. to 11 p.m. weekdays
Off-peak	- 11 p.m. to 7 a.m. weekdays plus all weekends and public holidays

RATE FOR PURCHASE FROM DIRECT CUSTOMERS (OVER 5,000 KW) DELIVERING ENERGY TO THE BULK ELECTRICITY SYSTEM ON AN OCCASIONAL BASIS ONLY

3.45 cents per kW.h multiplied by the capacity factor of the generator for the month of delivery, with a floor price equal to the energy rate applicable to direct customer purchases from Ontario Hydro.

Amir Shalaby is Supervising Engineer in the System Planning Division of Ontario Hydro.

FIGURE 1

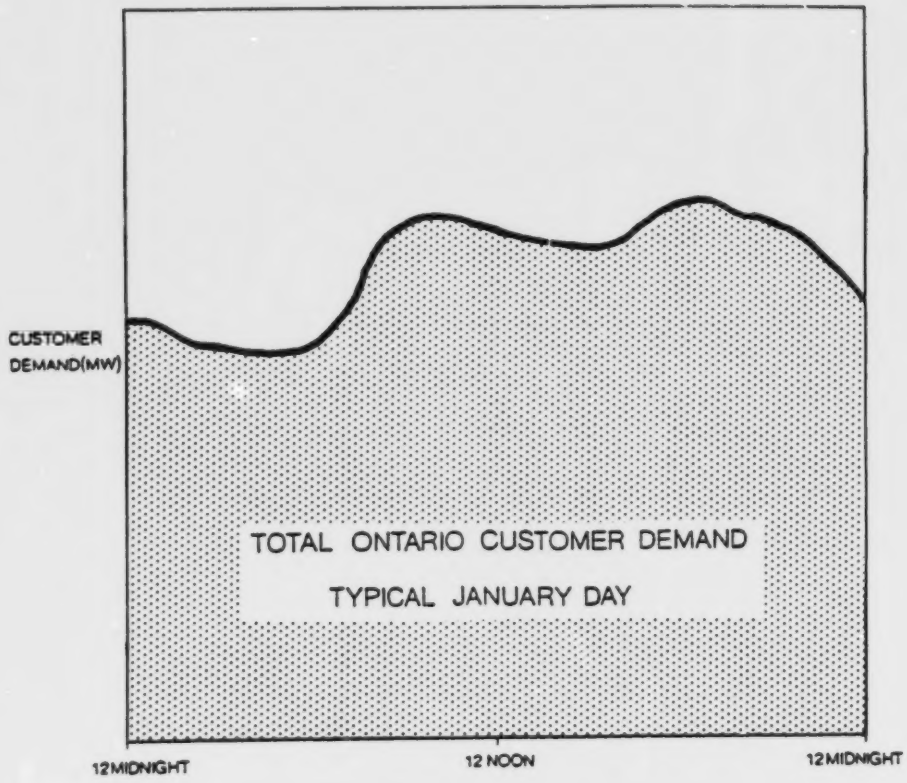


FIGURE 2

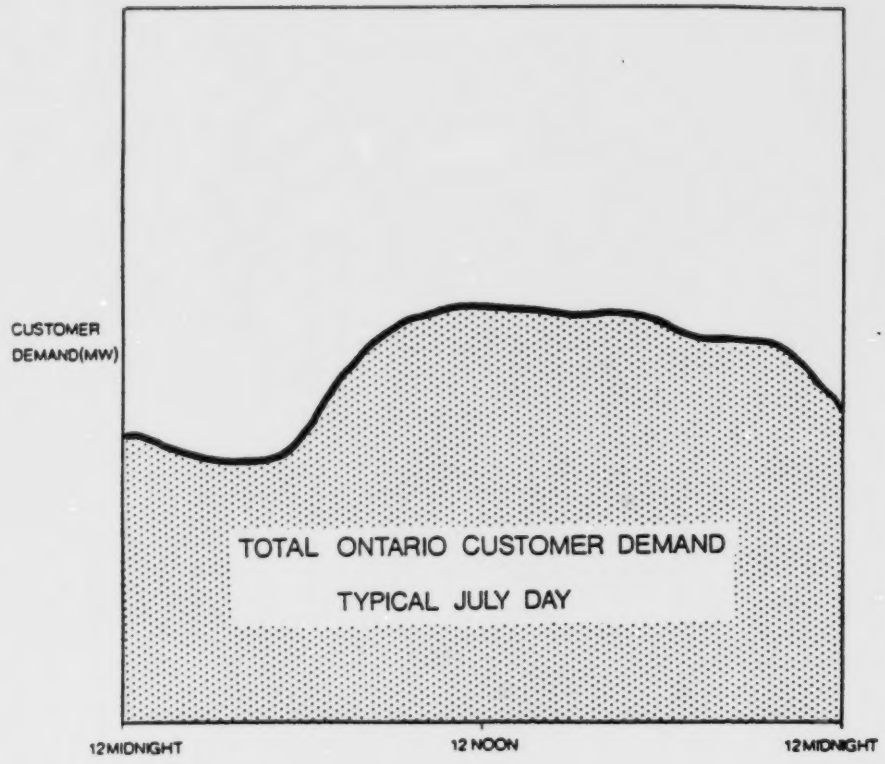


FIGURE 3

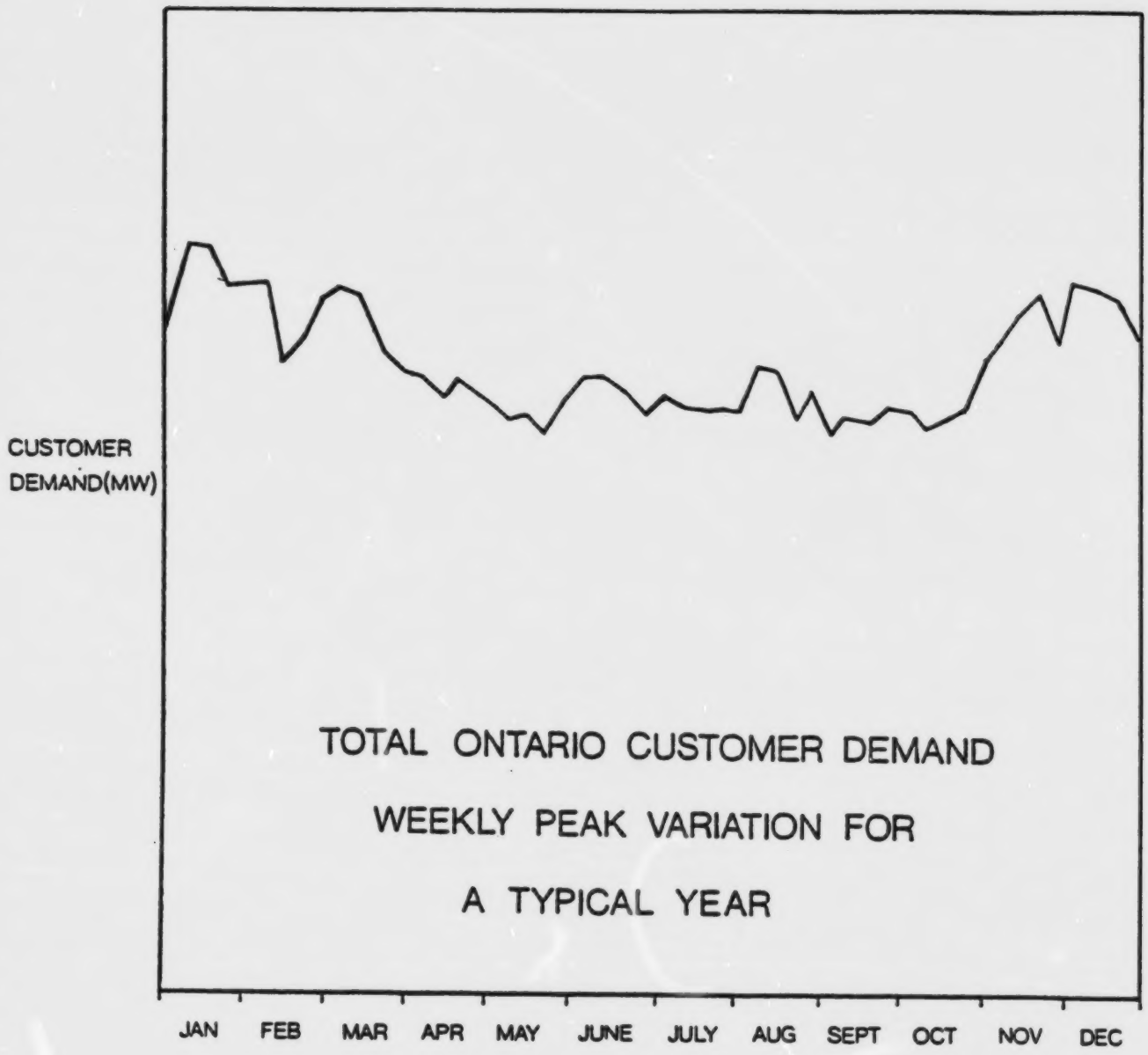

CUSTOMER
DEMAND(MW)
TOTAL ONTARIO CUSTOMER DEMAND
WEEKLY PEAK VARIATION FOR
A TYPICAL YEAR
JAN
FEB
MAR
APR
MAY
JUNE
JULY
AUG
SEPT
OCT
NOV
DEC

FIGURE 4

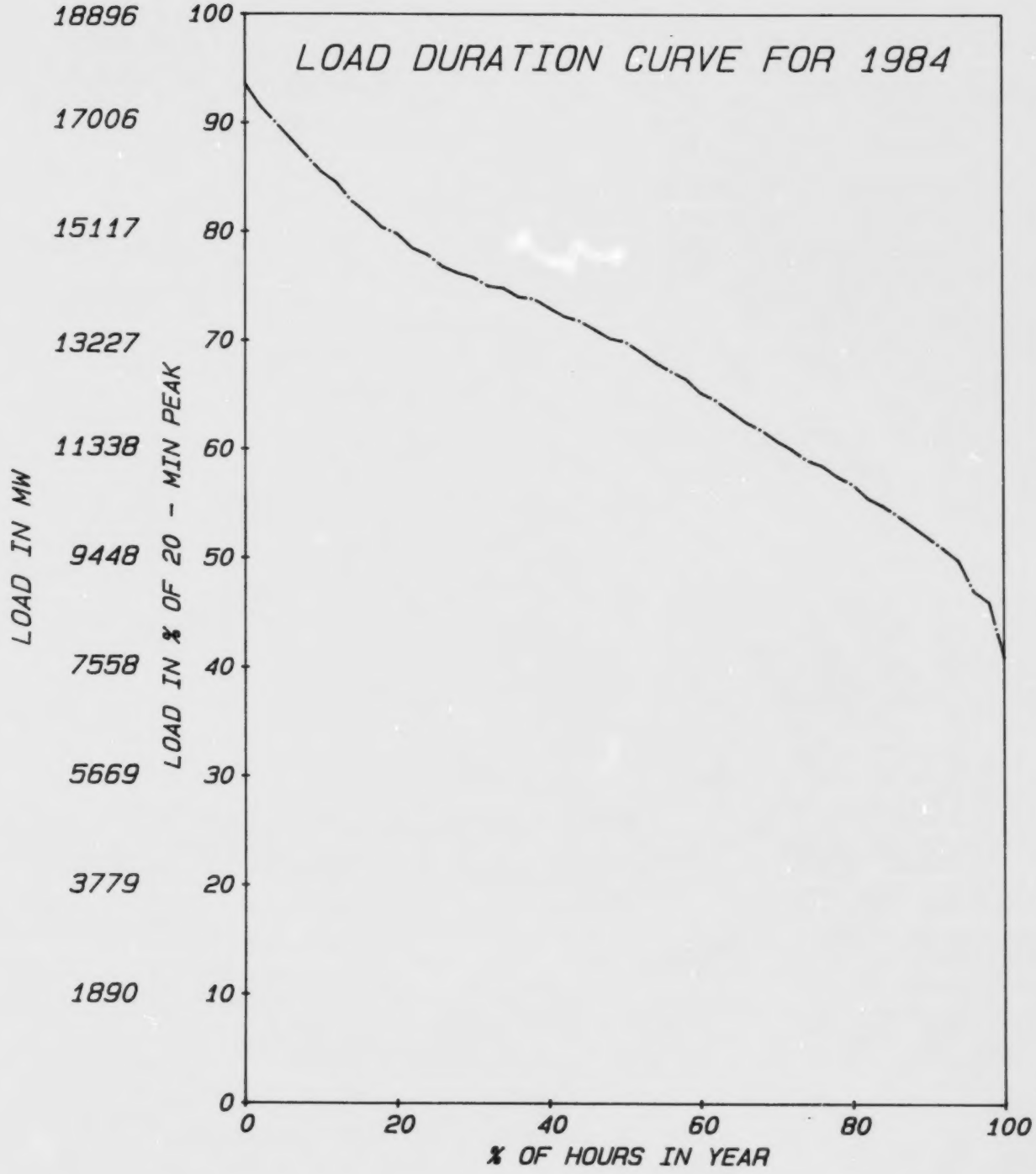

LOAD DURATION CURVE FOR 1984
LOAD IN MW
LOAD IN % OF 20 - MIN PEAK
% OF HOURS IN YEAR
18896
17006
15117
13227
11338
9448
7558
5669
3779
1890
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100

Figure 5

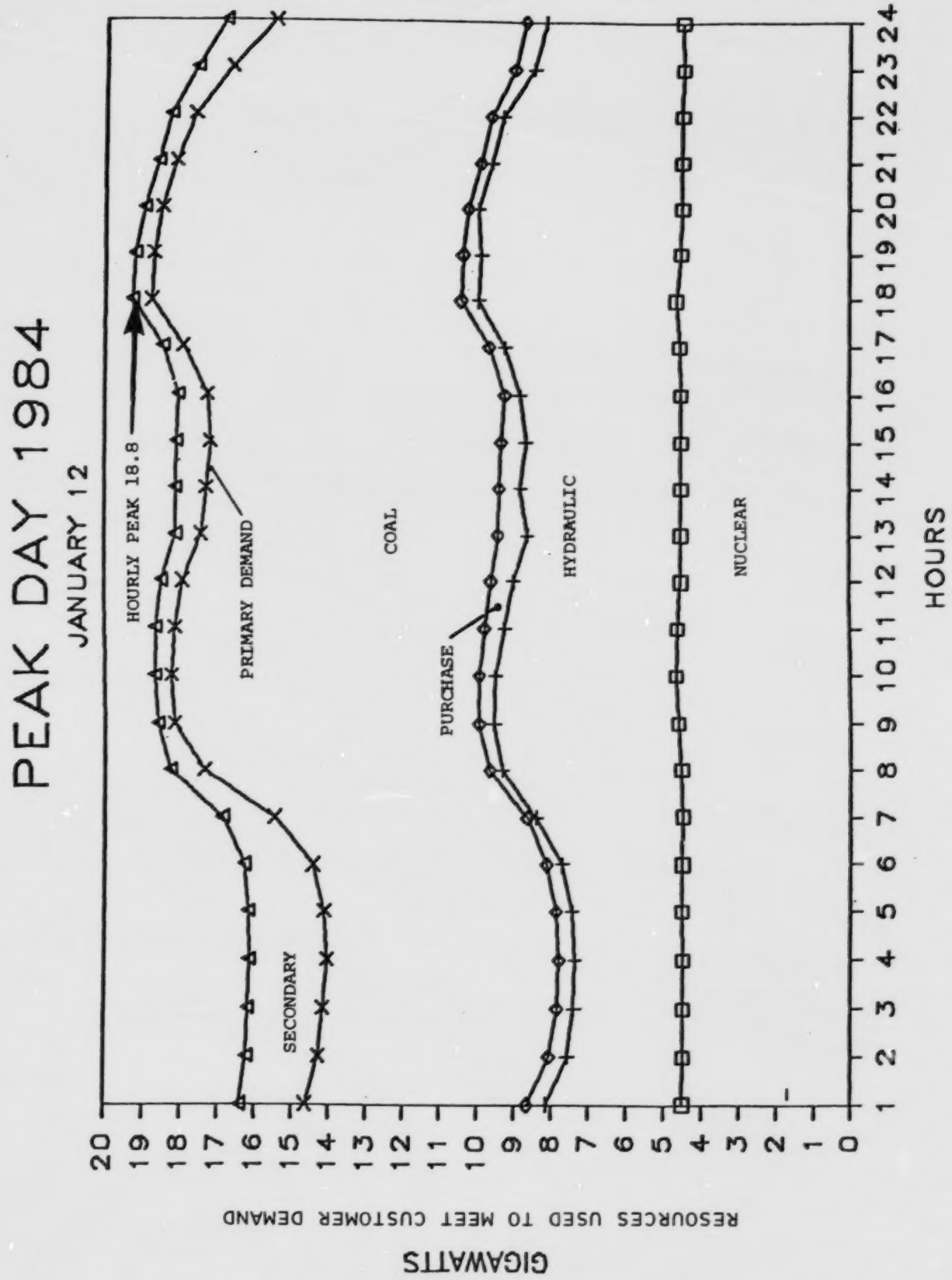

PEAK DAY 1984
JANUARY 12
HOURLY PEAK 18.8
PRIMARY DEMAND
SECONDARY
COAL
PURCHASE
HYDRAULIC
NUCLEAR
GIGAWATTS
RESOURCES USED TO MEET CUSTOMER DEMAND
HOURS
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20

FIGURE 6

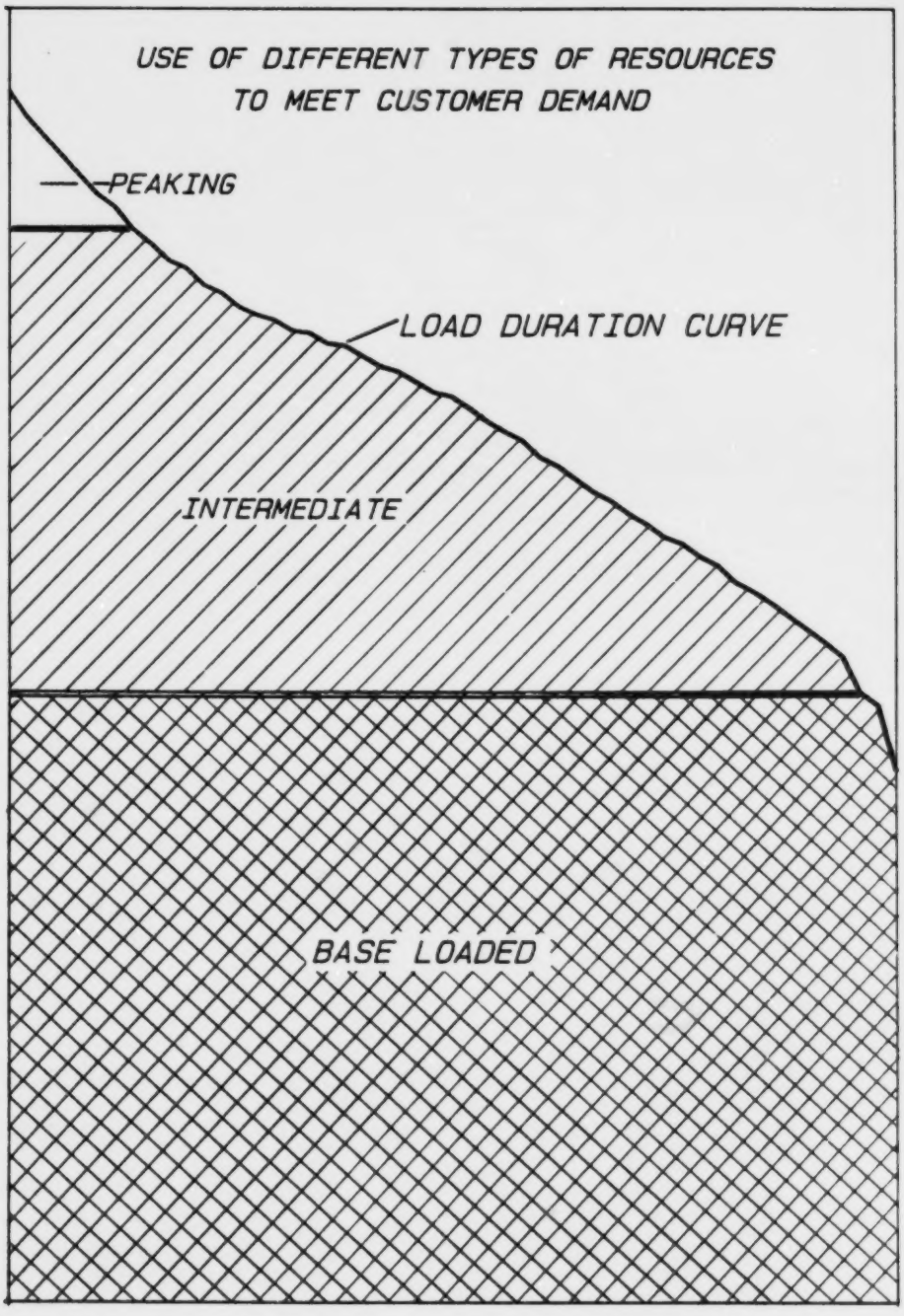

USE OF DIFFERENT TYPES OF RESOURCES
TO MEET CUSTOMER DEMAND
PEAKING
LOAD DURATION CURVE
INTERMEDIATE
BASE LOADED
DEMAND
IN
MW
HOURS OF YEAR

FIGURE 7
IMPACT OF INCREMENTAL DEMAND
ON USE OF RESOURCES

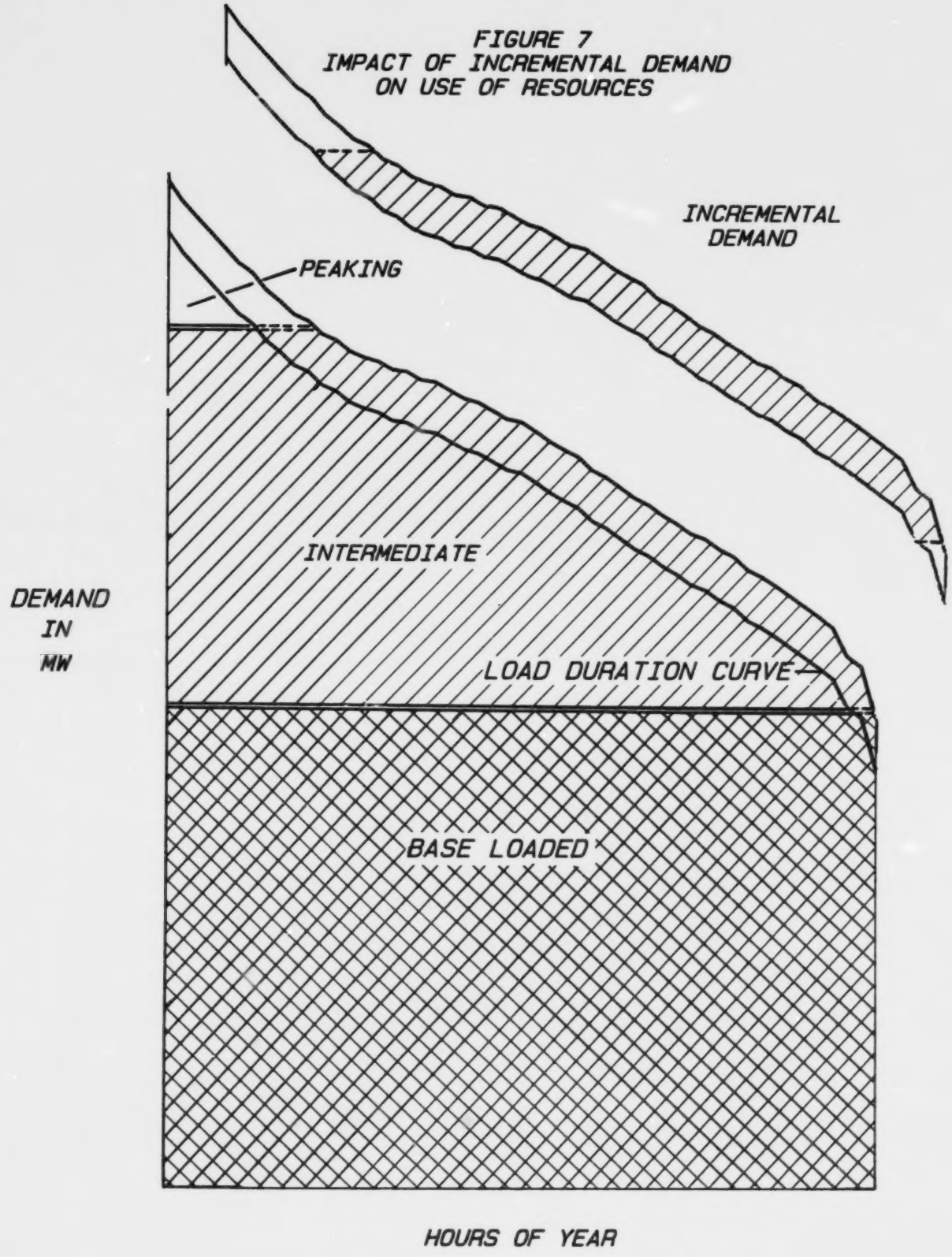
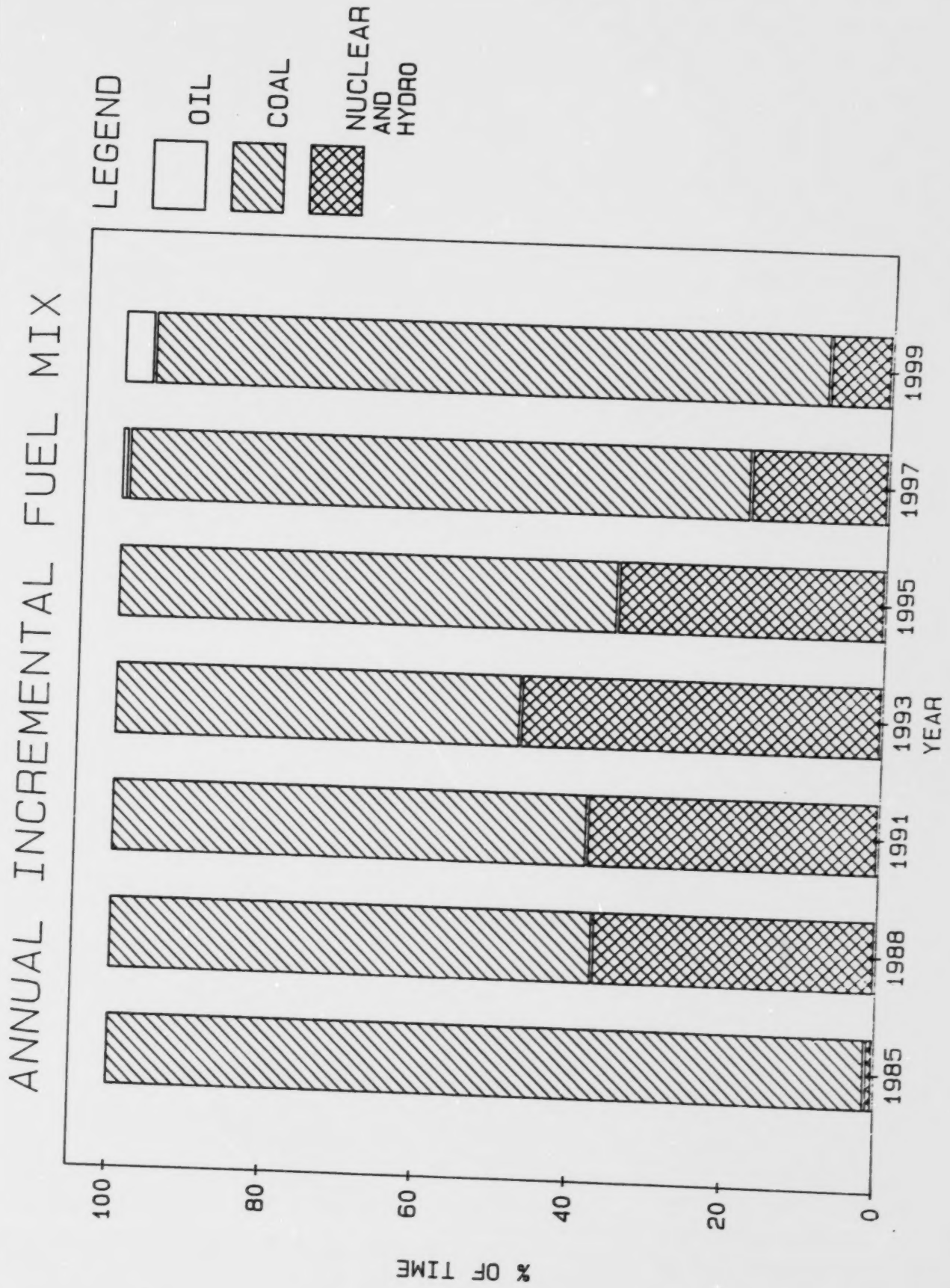


FIGURE 8


ANNUAL INCREMENTAL FUEL MIX
LEGEND
OIL
COAL
NUCLEAR AND HYDRO
% OF TIME
100
80
60
40
20
0
1985
1988
1991
1993
1995
1997
1999
YEAR

INCREMENTAL FUEL MIX

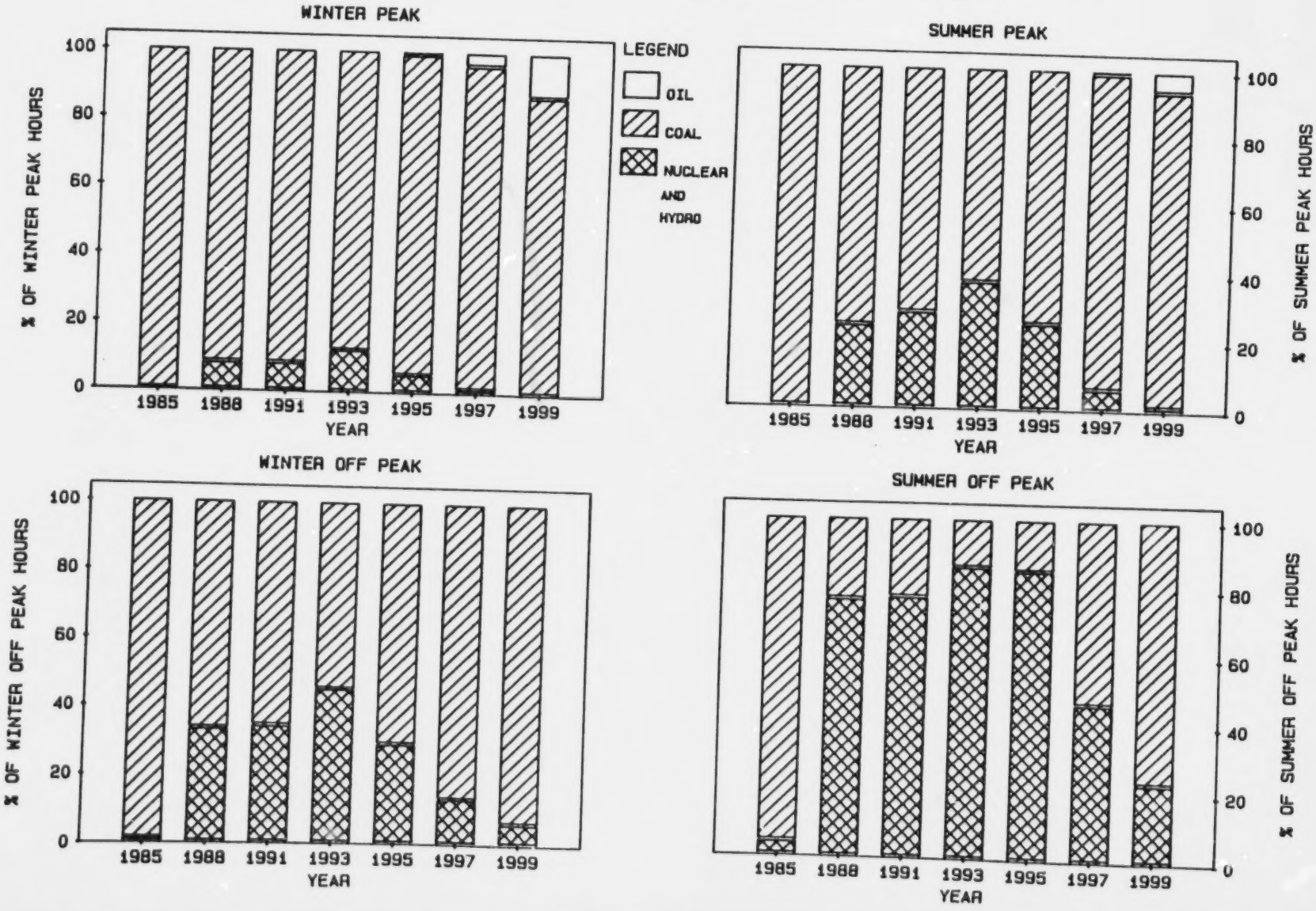


FIGURE 10

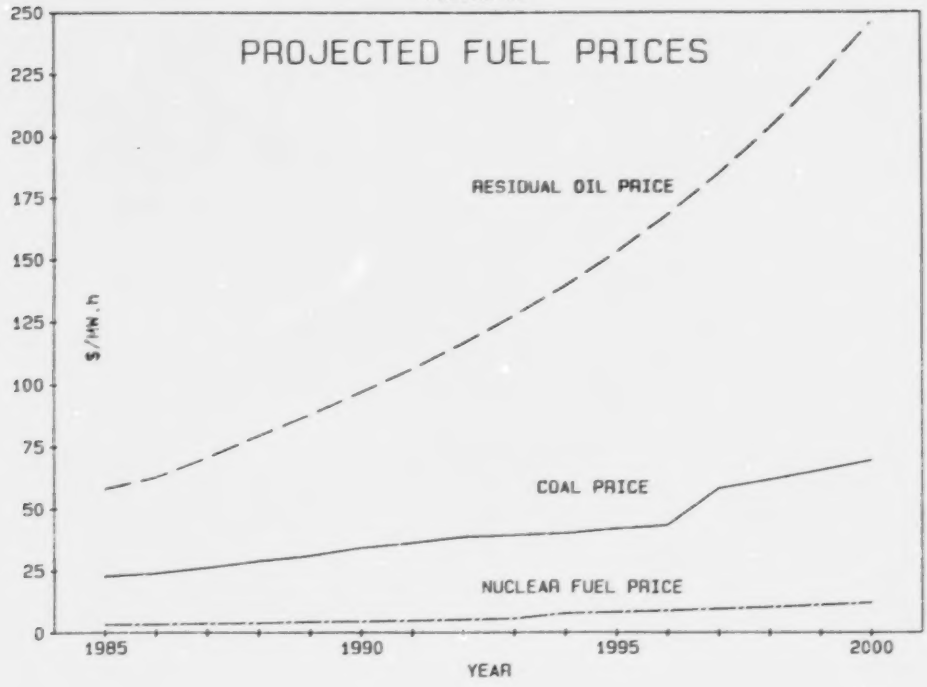


FIGURE 11

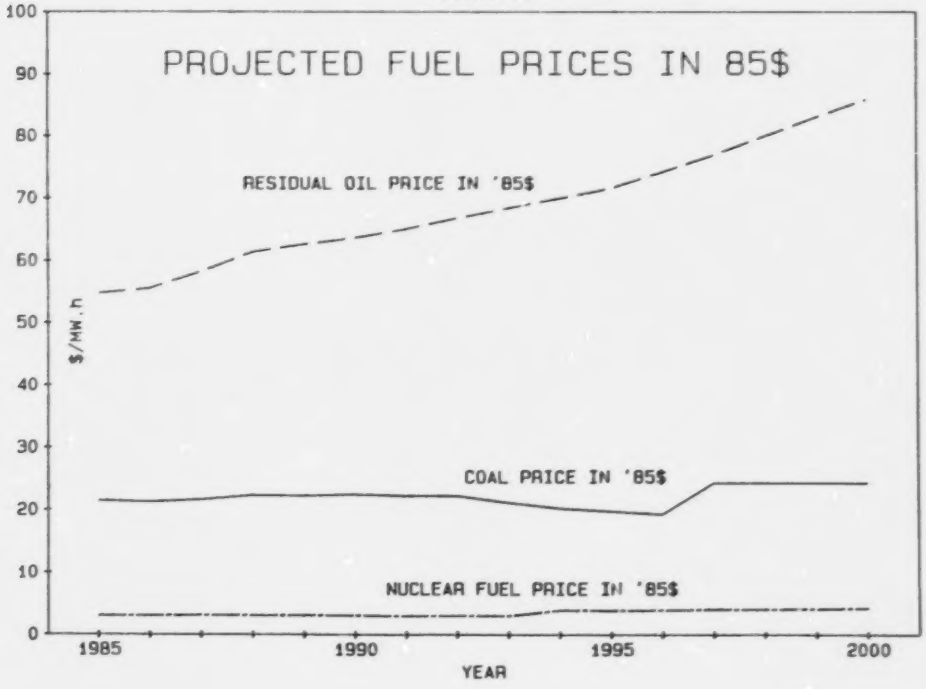
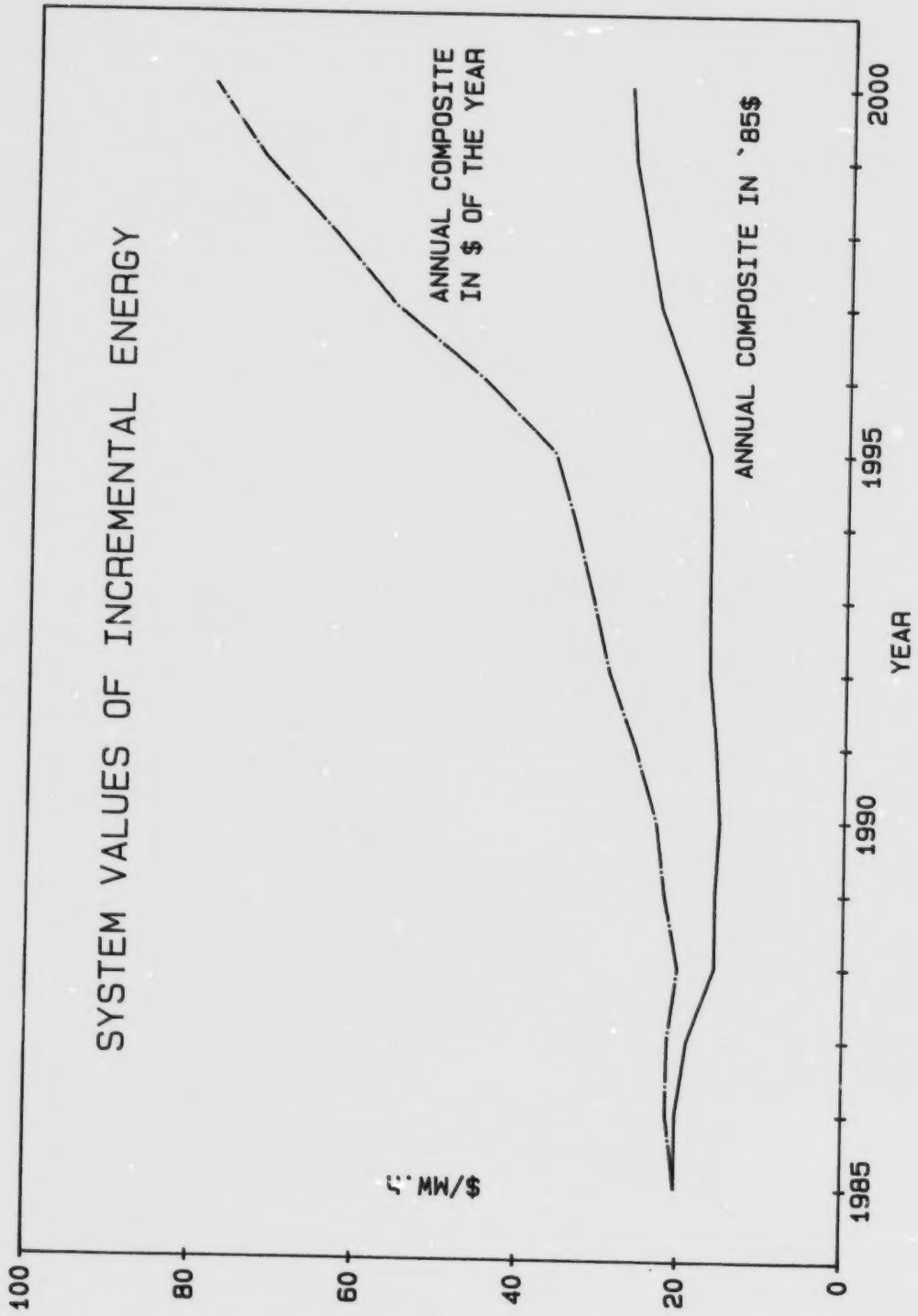


FIGURE 12


SYSTEM VALUES OF INCREMENTAL ENERGY
ANNUAL COMPOSITE IN $ OF THE YEAR
ANNUAL COMPOSITE IN '85$
$/MW
100
80
60
40
20
0
1985
1990
1995
2000
YEAR

INCREMENTAL SYSTEM VALUES

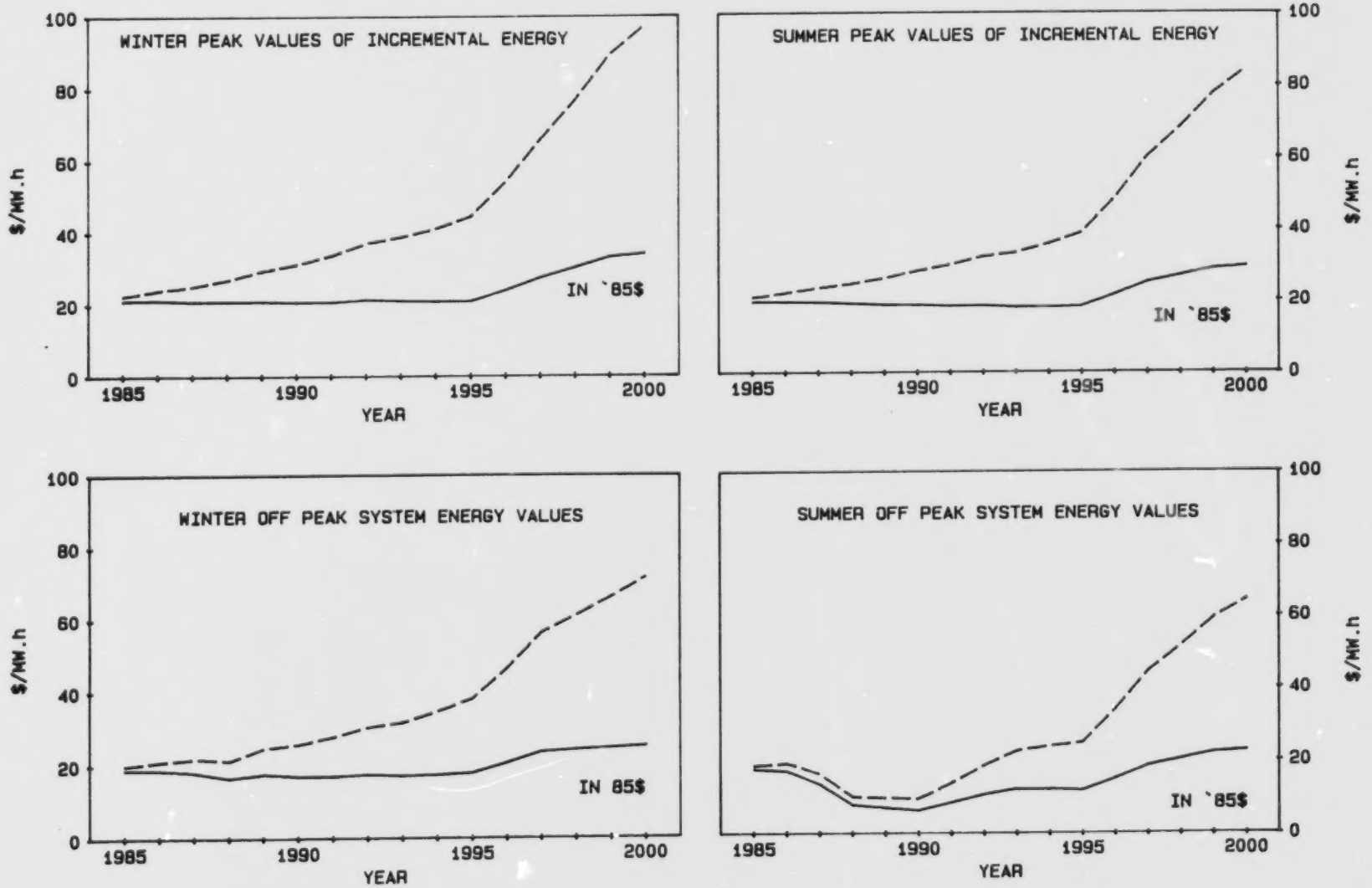
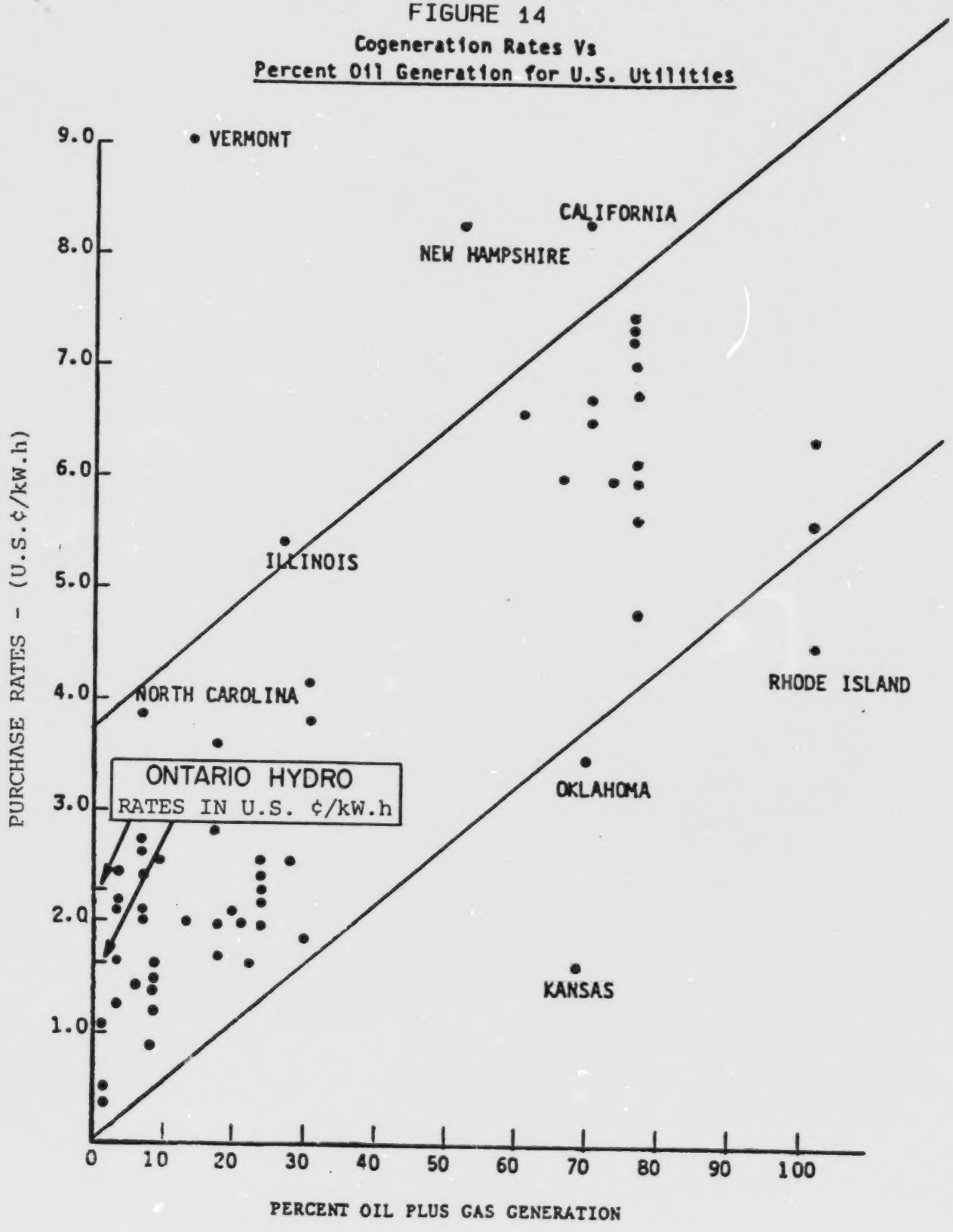


FIGURE 13

FIGURE 14

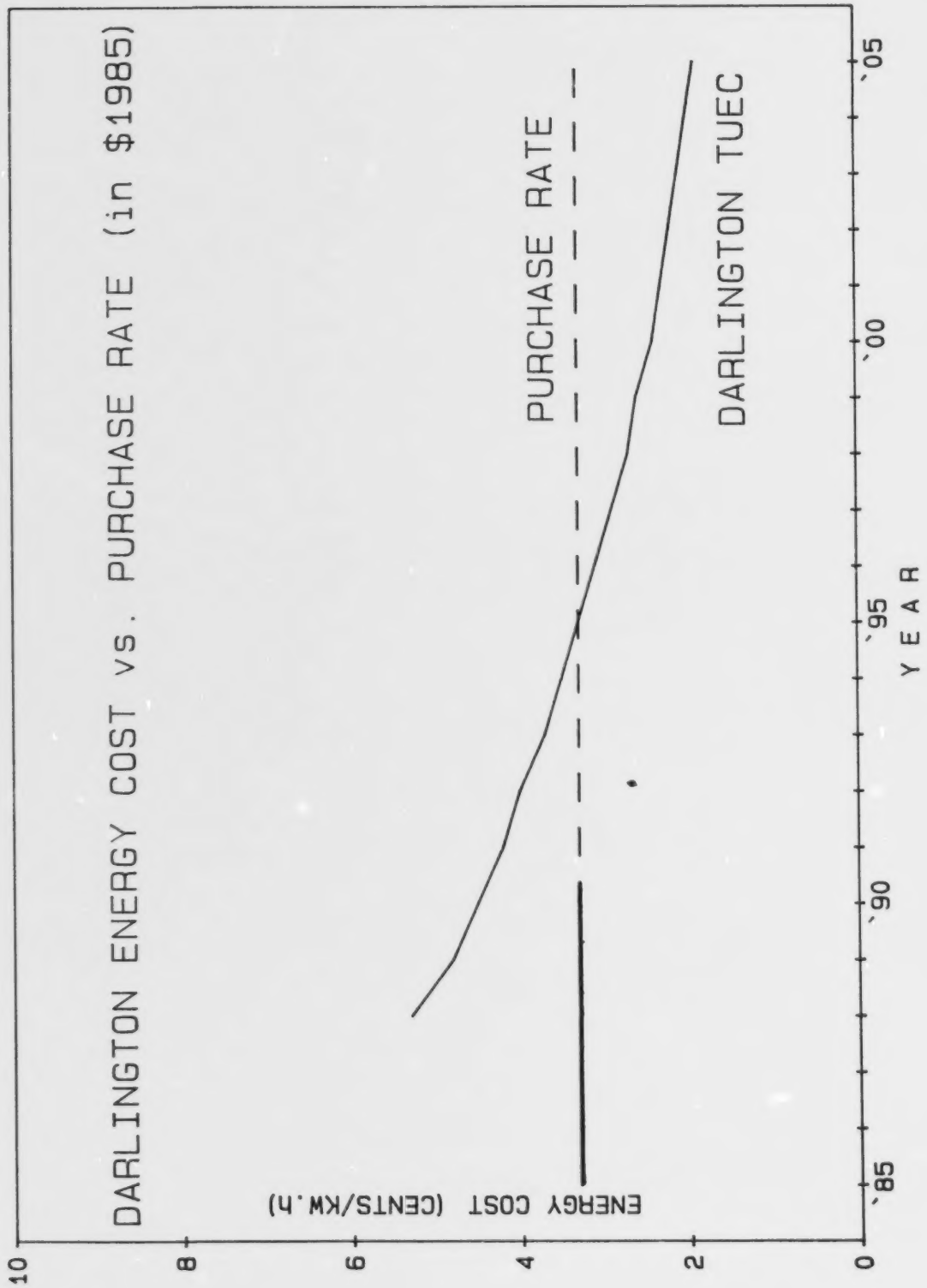
Cogeneration Rates Vs

Percent Oil Generation for U.S. Utilities



Source: Cogeneration: Regulation, Economics and Capacity
Energy Information Administration
U.S. Department of Energy - April 1983

FIGURE 15


DARLINGTON ENERGY COST vs. PURCHASE RATE (in $1985)
PURCHASE RATE
DARLINGTON TUEC
ENERGY COST (CENTS/KW.h)
YEAR
0
2
4
6
8
10
'85
'90
'95
'00
'05

KEYNOTE ADDRESS

REMARKS BY

THE HONOURABLE VINCENT G. KERRIO

ONTARIO MINISTER OF ENERGY

AT THE

SMALL HYDRO '86 CONFERENCE

SKYLINE HOTEL, TORONTO

WEDNESDAY, MARCH 5, 1986

7:00 P.M.

CHECK AGAINST DELIVERY

Thank you, and good evening everyone. It gives me a very good feeling to see so many of you here tonight.

This conference is dedicated to small hydro, something I have a very strong personal interest in.

I am sure someone in this room is going to say: "What does this guy know about small hydro -- he's from Niagara Falls."

Well, I'm very proud to be from Niagara Falls. And tonight I'm here to talk to you as Ontario's Minister of Energy -- something that I am also very proud of.

Like many of you in this room tonight, I have a background in small business. We were not brought up to believe that bigger always means better. We know the real meaning of the phrase, "small is beautiful".

We also know that, when it comes to doing business, "small" can also mean highly efficient, flexible, and cost-effective. This applies very much to small hydro -- an Ontario industry that is poised for growth.

Hydroelectric power has always been extremely important to Ontario's industrial development. It is still -- and will continue to be -- one of our most vital resources.

Historically, hydro's importance in the industrial development of this province cannot be overestimated.

In the early part of this century, there were hundreds of small independent hydro plants, providing power for many Ontario mills and factories. As the centralized grid system developed, many of these small plants were considered uneconomical, and were closed down.

But since the energy crunch of the early 1970s, there has been a growing interest in rebuilding these abandoned sites -- because small hydro makes good business sense once again.

We can all be very proud of what this province has achieved in the field of hydroelectric power. Ontario Hydro is respected all over the world for its technical expertise in this field.

But today we face new challenges, and new opportunities. The new Government of Ontario strongly supports the full development of the province's hydraulic resources.

At the same time, we are taking great care to ensure this development is consistent with our other public policies -- and in particular, the protection of our environment.

Why -- in this age of megaprojects and high-technology -- is the Ontario government supporting the development of small hydro power?

Well, the answer to that question is probably obvious to most of you. Simply put, small hydro power has many unique benefits.

Hundreds of small hydro sites are available, and these resources are indigenous to Ontario. In fact, some of the more than 30,000 rivers and streams in this province already have dams that have not yet been developed for power generation.

Small hydro is a natural for Ontario -- especially in those remote areas of the province that do not have easy access to the utility grid.

As well, hydroelectric installations are almost inflation-proof, and very long-lived. A well-built small hydro system will last at least 50 years. And these hydraulic resources are re-usable: The water is not wasted.

But perhaps most important is the fact that the small hydro generation process is environmentally benign. We believe small hydro has an important role to play in our strategy to fight acid rain and acid gas problems.

Because of these unique advantages, the new Government of Ontario believes very strongly in small hydro's potential. We see three main players developing this potential: Ontario Hydro, the private sector, and local communities, including municipal utilities.

Ontario Hydro has an important role to play in meeting Ontario's electricity demand -- now, and in the years ahead. Hydro must therefore continue to maintain and expand its existing plants, in an orderly and economical manner.

But, in addition to its role in large hydro developments, Ontario Hydro will also have an active role to play in helping develop small hydro projects.

Earlier this week, at the conference of the Ontario Municipal Electric Association, I released a new information paper on parallel generation in Ontario.

The paper may be of interest to those of you who may one day want to sell power to the provincial grid. And it is especially relevant to small hydro.

The Ministry of Energy has also produced a new book, entitled Streams of Power -- devoted to the story of small hydro in Ontario. Both these publications are available at the ministry's display here in the hotel.

When we talk about developing small hydro's great potential, one of the fundamental questions we need to look at is the role of the private sector and local communities. Indeed, that is one of the principal reasons for the conference here this week.

Over the past few years, the government has undertaken several programs to encourage small hydro in Ontario.

These efforts have included:

- new government policies;
- demonstration installations to help Ontario's small hydro industry build up its capability;
- and funds for feasibility studies by municipalities and conservation authorities -- to determine small hydro's potential in dozens of local communities across Ontario.

Through these early programs, we learned a lot about the viability of small hydro projects here in Ontario -- and we helped establish a vital new industry.

That industry is now eager for more challenges -- and I can assure you that this government is going to do everything it can to make those challenges available.

We have already started to remove a lot of unnecessary barriers to the development of small hydro sites by qualified private initiative.

For example, we have begun to streamline our small hydro approvals process within the Ministry of Natural Resources. As a result, private developers will find it a lot easier to get a small hydro project under way.

As you may know, I hold both the Energy and Natural Resources portfolios. And I am committed to ensuring that both my ministries work together to encourage small hydro in Ontario.

We are very happy with the progress we are making in developing small hydro in southern Ontario. In the more isolated northern regions of the province, however, it is a somewhat different story.

In Northern Ontario, many areas are located too far from the provincial grid to gain access to it economically. Many of these areas depend on expensive diesel/electric generators for their power.

As we all know, oil prices are subject to large fluctuations, and oil is generally quite expensive. This uncertainty and these high prices are unacceptable. Over the past few years, communities dependent on diesel generators have been paying between five and 10 times the price of comparable grid electricity.

Within the Ministry of Energy, we have recently initiated a Northern Small Hydro grant program -- a program that addresses the particular needs of these remote regions. We are hoping this program will encourage private enterprise to look very closely at the potential of small hydro in Ontario's northland.

Earlier today, you heard Pam Townsend talk about a small hydro success story at Frontier Lodge, near Elliot Lake. Our surveys show that there are several hundred similar tourist resorts that could benefit from a small hydro system.

There are also dozens of mining and forestry operations in the remote regions of the province that could benefit immensely from having their own, low-cost source of power.

Some mines in the North were forced to close down because of soaring oil prices and a depressed metal market. Some of these could probably be re-opened, if cheap hydro power were available -- and many unemployed northern miners would be back at work, as a result.

The Northern Small Hydro program provides capital cost assistance for commercial and industrial enterprises such as these. We see tremendous potential for the development of small hydro in the northern regions of this province.

In southern Ontario, the situation is quite different. Here, most areas have access to the Ontario Hydro grid system.

Through the Municipal Feasibility Assistance program, the Ministry of Energy has established an inventory of locations with good small hydro potential. Now, we can concentrate more on implementation.

I mentioned earlier that there are almost 600 small hydro sites in southern Ontario -- locations that were abandoned years ago as cheaper power became available. Many of these sites could be developed into real money-makers -- at comparatively little cost.

To make small hydro development more attractive to private investment, we need to improve the financial climate. This is already starting to happen.

Some of the financing proposals we have received for the Trenton and Burk's Falls projects are extremely creative, and clearly demonstrate the interest of the financial community in small hydro development.

Our municipal feasibility assistance program has done its job well, and the government has concluded that further efforts in this direction are no longer needed. As a result, our existing municipal program will be dropped.

In its place, we will provide grants of up to $5,000 towards the front-end costs -- engineering, legal, consulting and financial.

This assistance program will also expire in about three years. Our role as government is to help you to get there on your own. We will provide whatever help is needed to get the project going -- after that it's up to you to keep it going.

In that regard, I am pleased to be able to make several announcements here tonight. These new initiatives will strengthen small hydro's already encouraging position in Ontario.

First, we are simplifying the tendering process at Crown sites in Ontario with existing facilities, such as dams. Development of these sites will still be publicly tendered, but the process will be a lot easier.

Where the lands are privately-owned, the landowners will be offered the first right to develop the sites.

Second, we have now clarified some of the policy issues regarding the definition and treatment of virgin small hydro sites.

These sites will continue to be offered for development on a "first-come, first-served" basis. A proponent will be required to develop the site within two to three years, or forfeit it. And no developer will be allowed to develop more than three sites at any one time.

Third, I have proposed changes in Ontario Hydro's rights to potential sites.

As you may know, Ontario Hydro has traditionally had first right of refusal on all sites with more than two megawatts of capacity. Tonight, I am pleased to announce that the government has decided to open up to private development all Crown-held hydro sites up to 20 megawatts.

For sites above this size, Ontario Hydro will still have first right of refusal. However, if the circumstances indicate that a particular site can be developed by private interests, they will have the government's full co-operation.

The fourth announcement I am making involves Ontario Hydro's buy-back rates for parallel generation.

In order for small hydro development to be attractive to entrepreneurs, they must be able to sell their electricity at attractive rates. As some of you may know, I have been working for several years to secure a better buy-back rate.

The present rate, as I am sure you know, is 3.45 cents per kilowatt-hour, and goes up in line with the consumer price index. The Ministry of Energy and Ontario Hydro are reviewing this rate -- and will make a recommendation to me within 60 days.

I am confident that we will find a workable formula to help stimulate the development of small hydraulic power in Ontario.

The new Government of Ontario firmly believes small hydro can be a profitable business for private enterprise. The small hydro industry is looking for opportunities, and poised for growth.

With the new initiatives I have announced tonight, I am confident that this growth can begin to take place.

You have all received your copy of our map of Ontario, showing the existing hydroelectric plants in the province. There are about 170 of them, each indicated by a red dot.

What it does <u>not</u> show are the hundreds of former abandoned sites that could be refurbished -- or the many hundreds of virgin sites in Northern Ontario that are awaiting development.

I would like to see a lot more red dots on this map in a few years' time. And after this conference, I hope that many of you will be out there making some of them.

Good luck to all of you -- and thank you.

ONTARIO PROGRAMS

ONTARIO'S SMALL HYDRO ENCOURAGEMENT PROGRAM

Ian R. Lewis
Ontario Ministry of Energy

INTRODUCTION

The harnessing of Ontario's abundant water resources played a crucial role in the early industrial and economic development of the Province.

In 1880, when electricity was first introduced, there were 10 small hydro turbine manufacturers in Ontario, shipping up to 2000 units annually. By the 1930's, however, the widespread availability of reliable and low-cost grid electricity caused many small hydro sites to become uneconomic. After WWII, inexpensive diesel generation led to the retirement of many remote small hydro sites.

By 1970, on the eve of the first oil price shocks, some 570 small hydro sites had been abandoned in Ontario, and only one small turbine manufacturer (Barber Hydraulic) remained. Rising energy prices through the 1970's reversed the decline of the small hydro industry and led to renewed interest, particularly among private investors, in redeveloping the old sites.

The growing recognition of small hydro as a reliable, economical and environmentally benign energy source, and the identification of numerous institutional and regulatory barriers to small hydro development led the Province to initiate policies and programs to encourage private small hydro developments in 1981.

In the ensuing five years, Ontario's small hydro industry has enjoyed spectacular growth. Today, even with the relative stabilization of energy prices, interest continues to grow.

The purpose of this paper is to review what has been done and accomplished through Ontario's Small Hydro Encouragement Program to date; to examine the problems and opportunities currently faced; and to describe the new directions being taken by Ontario as a result.

DEFINITIONS

'Small Hydro' generally refers to hydroelectric power generation at sites with less than 20 MW average capacity.

Typical small hydro installations range from 500 kW to 5 MW in capacity (enough to power 50-500 homes). Systems that are smaller than 100 kW are often termed 'micro-hydro' and systems between 100 kW and 1 MW are often termed 'mini-hydro'. Small hydro systems are usually grid-connected in the South,

competing with utility supplied electricity, and off-grid in the North, competing with diesel-electric generation.

Throughout this paper small hydro plant capacities and resource potentials are given in average megawatts (MW). An average megawatt corresponds to 8760 MWh of annual energy production i.e. a 1 MW plant operating at a 100% capacity factor throughout the year. Actual installations will operate with capacity factors in the range 35-95%.

POTENTIAL OF SMALL HYDRO

The total hydroelectric potential of the province is approximately 8000 average MW, of which 56% or 4500 MW is currently developed and 3500 MW is as yet undeveloped. Much of this undeveloped potential is along the major rivers of the Hudson Bay watershed. Development in this region would require resolution of significant economic, social and environmental concerns. Also included in this undeveloped potential is 550 MW (2072 MW installed) available through the development, redevelopment or expansion of 17 Ontario Hydro sites.

The total operating small hydro capacity in Ontario stands at 567 MW. 193 MW of this is operated by Ontario Hydro, 52 MW by other public agencies such as municipal utilities and conservation authorities and the balance - 323 MW or 57% of the installed capacity under 20 MW, by private operators. Altogether, the existing small hydro capacity comprises 7.7% of our 7395 MW total developed hydroelectric capacity.

The total undeveloped potential of small hydro sites up to 20 MW in size is estimated to be about 700 average MW, or 20% of the remaining potential. Some 500 (installed) MW can be readily developed, with minimal environmental impact, at 225 formerly developed sites. Virtually all of these would be grid-connected. The potential for off-grid small hydro is more difficult to assess, but is estimated to be on the order of 100 (installed) MW at 20-50 sites with nearby loads.

To put these figures in perspective, the current (dependable peak) grid-connected generating capacity in Ontario is 22,613 MW, 30% of which is hydraulic. The requirement for new generating capacity, starting in the early to mid 1990's is expected to be 300-400 MW annually. Off-grid demand in Ontario is met by an estimated 40 MW of diesel capacity, generating about 70 000 MWH and consuming some 26 million litres of diesel oil in 1984. If the an average delivered fuel cost were $0.40/l, the corresponding fuel expenditure would be $10 million.

The prospects for the small hydro market in Ontario will be addressed at the conclusion of this paper. At this point we note that even a high level of new small hydro development, say 100 average MW or about 15% of the remaining potential is a minor contribution to the overall Provincial energy picture. Why then should we be interested?

BENEFITS OF SMALL HYDRO DEVELOPMENT

Though small hydro cannot be expected to form a major fraction of our bulk electrical supply, it is nevertheless significant at the local level and as a component of capacity additions.

Among the many benefits of small hydro, compared to other generation options, we note the following:

a) It is indigenous. Not only is waterpower a domestic energy resource, but we also have within the province the manufacturing, engineering, and financial capability to develop it;

b) It is renewable and long-lived. A well-designed and maintained small hydro plant will operate for a century or more. We have runners in operation today that are more than 120 years old.

c) It is environmentally benign. Hydroelectricity is non-polluting and produces no waste heat. Adverse impacts are often negligable and, for small installations, essentially non-existant. To the extent that small hydro substitutes for coal or oil-fired generation, or provides flood or ice control, small hydro developments should be seen as environmentally beneficial.

d) For the utility, privately-financed small hydro provides additions to capacity 'off the balance sheet' allowing the utility to increase revenue without incurring additional debt. As small hydro plants can be implemented quickly - in 2 to 5 years - the utility can also enjoy the advantage of being able to more closely match generating resources to demand growth.

e) It provides local economic benefits. A small hydro development, by an off-grid business or a municipal PUC has an immediate and tangible impact in terms of local jobs, reduced energy costs and increased local tax revenues.

f) Finally, we have the larger industrial and export opportunities. Fabian Acker's paper estimates the worldwide small hydro potential to be between 157 and 450 thousand MW. Frost and Sullivan have estimated that some 20 thousand MW, about 7% of the ultimate potential, will be installed over the next 10 years. We are then talking about a world market of $3-5 billion a year, well within our capacity to serve competitively. Ontario's share of world exports averages 2%, so we should be expecting to export on the order of $150 million annually in small hydro goods and services. Currently we are only exporting about a tenth of this.

Clearly then, with these many benefits, small hydro is worthy of encouragement.

ROLE OF GOVERNMENT

The government of Ontario has a central role to play in the development of small hydro, stemming from the Crown-ownership of resources and the closely related provincial jurisdiction over electric power production. Though the government does not, itself, design or build small hydro plants, it is up to provincial government policy to create a climate that is either encouraging, or inhibiting, to small hydro development.

The legal situation in Ontario is quite different from that in the U.S. for example, in that the ancient proprietary rights of the Monarch persisted past colonial times and became vested in the government. The notion of 'crown' land means that ownership of all of the land in the province, and all of the timber, mineral, water and other resources is vested in the government, unless specifically deeded away.

In fact, this is fortunate in that it greatly simplifies the approvals process. Except for remote native communities, administered by the Federal Department of Indian Affairs and Northern Development, or navigable waterways where Parks Canada or the Coast Guard may be involved, the approval of a small hydro project generally involves dealing with only one organization: the district office of the Ministry of Natural Resources. Compare this with the U.S. where the approval of a given project could easily involve ten or more different jurisdictions.

Ontario Hydro - originally the Hydroelectric Power Commission of Ontario - was established by statute in 1904 to ensure that the province's water powers were developed to provide power at least cost to the public.

The province has traditionally preferred public development of waterpowers. A result of this policy is that electric power costs dropped dramatically, being halved shortly after Hydro began to interconnect the municipal systems, and being halved again following the development of Niagara and other large water powers. All of the bulk generation in Ontario was hydraulic until 1952, when the first fossil-fired plant was commissioned. Still, over 70% of the electrical energy supplied in the province in the last 25 years has been from hydraulic sources.

With the changing economics of small hydro in the late-1970's and the clear interest of municipalities and private businesses in undertaking small hydro projects, it became apparent that the provinces waterpower development policies should be re-examined.

POLICY

On March 26, 1981, Cabinet approved a new Policy on Private Sector Involvement in Small Hydroelectric Development. The policy noted that the government favoured the continued development of Ontario's indigenous hydraulic resources, where

this was consistent with social and environmental objectives and concerns.

The policy contained the following elements:

a) that Crown-held sites up to 2 MW in size be made available for private (that is, other than Ontario Hydro) development. This recognized an Ontario Hydro resolution of December 1980 in which it indicated that it had no desire to develop sites this size;

b) that Ontario Hydro continue to be accorded its traditional first right of refusal for sites larger than 2 MW. The policy added, however, that where a private interest had been indicated, Ontario Hydro must exercise first rights within 3 months and present the government with a plan for expeditious development. The implication is that the government would choose the best proposal; and,

c) that the Ministries of Energy and Natural Resources cooperate to design and implement a Small Hydro Encouragement Program, reporting on results achieved in 1986. This conference constitutes that report.

ENCOURAGEMENT PROGRAM: FIRST FIVE YEARS

PROGRAM GOALS AND OBJECTIVES

The goal of the Small Hydro program is to create a climate in Ontario that will encourage the development and redevelopment of small hydraulic sites by the private sector and by public agencies other than Ontario Hydro.

In 1981, a specific target for the program was set as encouraging the installation of an additional 100 MW of small hydro by 1995, aside from developments undertaken by Ontario Hydro. This target is to be achieved through actions to reduce marketplace and other barriers to small hydro development, rather than through permanent subsidies.

PROGRAM STRATEGY

Small hydro projects, even retrofits onto existing dams where environmental problems are minimal, are still very complex compared to other energy projects. Factors contributing to this complexity include:

a) need for site specific engineering and design;

b) need to secure legal rights, including regulatory approvals to develop the site;

c) need to carry out costly feasibility studies before an investment decision can be made;

d) difficulty in obtaining financing for capital intensive projects;

e) need to negotiate power sale agreements with local utilities; and

f) the relative lack of experience of all involved with small hydro development in the 1980's environment.

In its efforts to deal with this complexity, the Ministry has found that two tools, support for feasibility study and limited demonstration, provided an effective means to encounter and resolve barriers in the marketplace. Effective communications are needed to transfer the lessons learned to the wider audience of site owners and developers.

ACTIVITIES

The following is a brief summary of the major activities undertaken over the last five years:

a) Inventories: In 1981, the two ministries initiated an update of the previous (1946) Provincial List of Water Powers, including a survey of 679 formerly developed sites and more detailed assessments of some of the most promising of these. MNR has recently published the updated Provincial List, and additional information is now being assembled at the Ministry of Energy for public use.

b) Streamlining Regulatory Approvals: The approvals process itself has not proved to be a significant barrier in Ministry-supported projects to date, though the Ministry's advocacy has undoubtedly assisted small hydro developers. For example, the Ministry is currently playing such a role in support of Trenton's efforts to develop a site under the jurisdiction of Parks Canada.

   New aspects of the approvals process are likely to be encountered in the Northern Small Hydro Program (see below), where a number of virgin sites will be proposed. The Ministries of Energy and Natural Resources are working closely together to improve the existing MNR procedures for the evaluation of these projects. John Morton's paper will review this area in depth.

c) Municipal Feasibility Assistance Program: A study of barriers and constraints to small hydro development found that municipal PUC's were in the best position to undertake small hydro development, but were barred by difficulty in obtaining funds to undertake the initial feasibility studies. The Ministry, therefore, inaugurated a program in 1983 to provide assistance for these studies and to inspect existing turbines.

To date, a total of 8 turbine inspections have been completed and 17 feasibility studies are either completed or underway, totalling 17.8 MW of small hydro capacity for a total investment of $26 million (i.e., $1,462/kw). A number of these municipalities are now seeking private finance to carry out feasible projects.

d) Demonstration Programs: There have been two demonstration programs to date: the three-site Micro-Hydro Demonstrations in 1981 and the seven-site Canada/Ontario Small Hydro Demonstrations in 1983. In addition, two off-grid demonstrations were carried out in 1984.

The objectives of the Micro-hydro Program were: to generate information on small hydro costs, to identify regulatory and jurisdictional bariers, and to validate the performance of small turbines being offered in Ontario. The Ministry provided 100% of the cost of the following three installations:

	NAME	TURBINE	TOTAL COST
1.	Dorion Fish Hatchery	16 kW Leroy-Somer	$ 82,200
2.	Millcroft Inn (Alton)	22 kW Galt	120,100
3.	Guelph Dam	80 kW Galt	79,000

Based on this experience, the Ministry developed the larger Small-Hydro Demonstration Program. The objectives of this program were to generate cost and performance information on larger systems, more typical of the majority of sites; to gain experience and encounter barriers in a more realistic market environment; and to test the practical application of Ontario Hydro's new parallel generation policy, including the problems of negotiating power sale agreements with local utility commissions. The bilateral program provided a maximum of 35% of installed cost at the following seven sites:

	NAME	TURBINE	TOTAL COST
4.	Fanshawe Dam (London)	500 kW Ossburger	$830,000
5.	Peterborough	200 kW reconditioned	226,800
6.	Kinsmen (Sault)	300 kW Barber	290,000
7.	Elora Mill	135 kW Galt	300,000
8.	Wilkes (Brantford)	130 kW Galt	340,000
9.	Thornbury	135 kW Galt	295,000
10.	Wilson Mill(Fergus)	75 kW reconditioned	56,000

As neither of these programs dealt with the special problems of remote, off-grid sites, two further projects were supported in 1984. These were:

	NAME	TURBINE	TOTAL COST
11.	Frontier Lodge	80 kW Galt	$200,000
12.	Quetico Park	18 kW Galt	95,000

e) Export Development: In 1982, the Ministry obtained Management Board approval to make a non-statutory conditional grant of $200,000 to Barber Hydraulic of Port Colborne, to assist them in obtaining a small hydro contract in Jamaica. This contract was eventually signed and installation is currently proceeding. The three-year delay is probably typical for such export activities. The project was coordinated through Ontario International Corporation.

f) Information Transfer: The Ministry of Energy sponsored three conferences on small hydro, each attended by approximately 300 delegates. The first of these was held in 1981, the second in 1983 and the third in March, 1986.

Publications resulting from the program include a study of Barriers and Constraints to Small Hydro Development, a report on the Micro-Hydro Demonstration Program, and a 'How-To' booklet on the development of micro-hydro sites. This latter document was enlarged and rewritten as the "Streams of Power" Handbook published by Renewable Energy in Canada.

ACCOMPLISHMENTS TO DATE

When the encouragement program was first initiated in 1981, small hydro experience in Ontario was virtually non-existent; the Ontario turbine manufacturing industry consisted of two weak companies; procedures for obtaining regulatory approvals or connecting to the utility-grid were unknown or not established; and there was a general lack of reliable information concerning the cost, performance or potential of small hydro.

As a result of the program, the nucleus of a viable small hydro industry has been established and has demonstrated its capability to design, manufacture and install these systems successfully. The two small hydro manufacturers have enjoyed sales growth averaging 20% annually (little of this directly from the Ontario program) and are making significant inroads into export markets.

Through the Municipal Feasibility Assistance Program, investment opportunities in excess of $25 million have been identified and documented. This magnitude has been sufficient to attract the interest of the financial community and, recently, has led to specific offers of private finance to municipalities. In the Small Hydro Demonstration Program, it was shown that a variety of different organizational types could successfully finance and implement projects.

Finally, a number of important policy, legal and regulatory precedents have been established. These include the parallel generation policy at Ontario Hydro, policies and rates for

'wheeling' of power to different locations, agreements for purchase and sale of power with municipal utilities and approvals of small hydro facilities under a variety of provincial and federal statutes.

CURRENT PROBLEMS AND ISSUES

While much has been accomplished since the inception of the program in 1981, a number of problems and issues remain to be addressed and resolved.

a) Problems remain in the approval of small hydro projects at the local level, despite the fact that most organizations with regulatory powers in this field have adopted encouragement policies and procedures. These policies have not always been effectively communicated to the district and regional staff who process and recommend applications.

b) The lack of a central policy and procedure for approving small hydro applications at the Federal level, whose jurisdiction includes remote native communities and the Trent, Severn, Rideau and other navigable waterways, is emerging as an issue. We are pleased that Parks Canada recently approved a small hydro policy and are now interested in how it will be implemented. The proposal of Trenton PUC to develop a site on the Trent River is helping to clarify this matter.

c) Project finance has emerged as a major concern, though substantial progress is being made in attracting the interest of the financial community in small hydro, and in developing new and innovative financial vehicles suited to projects of this type.

   The financial community has indicated that progress in two areas would markedly improve the investment climate for small hydro. First, Ontario Hydro and the municipal utilities should offer longer-term and more flexible contracts for the purchase of power (e.g. 10 to 20 years), particularily in support of "innovative" financing schemes. Second, the investor needs a single party on each project to assume (e.g. through performance bonds and insurance) the full responsibility for 'completion risk': the risk that the project will not be completed on time or within budget, or that the equipment fails to meet design performance levels. Galt, Barber and others are addressing this by undertaking projects on a 'turn-key' basis.

   Success in these two areas would allow the debt component of small hydro project finance to be increased significantly, increasing the availability of funds and lowering the overall cost of capital to the project.

d) Closely related to the problem of finance is the economic environment established by tax rules, buyback rates and general factors such as energy prices, inflation perceptions and interest rates.

With the buyback rate at 3.45¢/kWh, a grid-connected system is economically viable (ROI exceeding 15%) only with installed costs of less than $1000/kW. The effect of tax incentives such as Class 34 CCA or SBDC financing is to increase the allowable capital cost by about 30% ie. into the $1300/kW region.

A limit of $1300/kW generally excludes new developments at existing dams, but allows most redevelopments and plant extensions. Given the paucity of sites that can be developed under $1000/kW, the tax incentives are obviously critical.

For projects, that displace purchased electricity, or equivalently for buyback rates in the range 4.5-5.0¢/kW, a project would be viable with capital costs around $1300/kW without tax incentives, and as high as $2000/kW with the existing incentives. The latter figure embraces virtually every project we have seen in our demonstration and feasibility study programs.

Off-grid projects displacing diesel can tolerate capital costs 5 times or more higher than grid-connected systems. Economics, per se, is not a constraint to off-grid projects.

e) The encouragement program has achieved a substantial impact in southern Ontario and for grid-connected systems, but little experience has been gained in the marketing, design, approval, finance and installation of small hydro in remote northern locations where it would substitute for expensive diesel-electric power. Gaining this experience is doubly important as it "simulates" the logistic problems the industry would face in offshore markets;

f) The cost of small hydro has continued to be a problem. There are two aspects to this barrier: organizational and technological.

The organizational aspect is that small hydro projects tend to be undertaken as miniature versions of large hydro-electric developments, with extensive engineering prefeasibility, feasibility and design studies. Small projects, however, cannot afford large engineering overheads, and the marginal returns to engineering labour are often very low. One alternative being explored in the Ministry's program is a two-step development process consisting of a 'reconaissance' stage where all necessary site specific information is collected, and followed by a 'design-build' stage, undertaken by a turn-key contractor. This approach is not suitable in all cases, however.

The technological aspect refers to the need to standardize and modularize all aspects of small hydro engineering, equipment and installation technique, with the development costs spread over multiple installations of similar units. While the benefits of this have long been perceived, the

control of small hydro projects by consulting engineers has denied manufacturers and contractors access to opportunities for standardization. Again, the advent of turn-key approaches, particularly with the close involvement of turbine manufacturers, should accelerate development in this area.

Overall, the two-step development process and greater standardization could potentially lead to a reduction of up to 20% in the installed costs of typical small hydro systems over the next 5 years.

g) Export development will become increasingly important, as the domestic market is too small to long sustain current rates of industry growth. Ontario Hydro and Ontario International Corporation both consider small hydro to be a potential "winner" in export markets. The current problem is to establish linkages between the industry and other players and to cooperatively develop an overall industry and market development strategy.

h) Finally, though a wealth of information and experience has been generated through the program, much of it has yet to be effectively transferred to the many different client groups. This includes not only technical and cost information, but also accurate information on the environmental impacts and benefits of small hydro development. There is an urgent need at this time to consolidate, publish and market this information.

ENCOURAGEMENT PROGRAM: THE NEXT FIVE YEARS

NEW DIRECTIONS

In 1985, following a reorganization of the Ministry, the existing small hydro programs and activities were repackaged into a single umbrella program. Previously small hydro responsibilities were fragmented among several organization units. This 'one window' approach not only streamlines coordination and delivery of the Ministry's responsibilities in this field, but also improves the Province's ability to respond to opportunities identified by the small hydro industry, site owners, municipal utilities and other client groups.

The existing (1981) policy statement has been reviewed and found satisfactory with one important change: that Ontario Hydro's traditional first-right of refusal to Crown-held waterpower sites are now revoked for all sites under 20 MW capacity, rather than 2 MW as was the case previously. This clearly signals the government's confidence in the private sector's role while removing some confusion over the government's definition of small hydro.

In support of this, efforts are underway to further clarify and reform the procedures for approval of sites on Crown lands or using Crown facilities. The current status of this work is described in the paper by John Morton.

Finally, the Minister has directed that a review of buyback rate policies and procedures be initiated. Ontario Hydro is due to report on this matter in May 1986.

GOALS AND OBJECTIVES

Activities in the coming years will continue along the lines previously established, but with increased emphasis on the following objectives:

a) the reduction of barriers and uncertanties that hinder the private financing of technically and economically viable small hydro projects.

b) the introduction and encouragement of off-grid small hydro developments in northern Ontario, including demonstration of the 'two-step' reconaissance/design-build process.

c) the establishment of linkages and cooperation between the industry, Ontario Hydro and the government to further increase small hydro exports.

d) the consolidation and transfer of the experience gained and lessons learned through the program.

PLANNED ACTIVITIES

a) Site Development Assistance: Previously, the Ministry assisted local government and conservation authorities through the Municipal Feasibility Assistance Program and private developers with staff time. As the volume of activity and interest in small hydro continues to expand, these approaches are becoming increasingly ineffective.

The new Site Development Assistance program will 1) shift public assistance to the earlier stages of project development (e.g. prefeasibility), 2) encourage the growth of a private sector infrastructure to provide engineering, financial and legal assistance to prospective developers, and 3) provide the same assistance to all developers, whether public of private.

This program will provide a maximum of $5,000 in grants to any one site. No more than 60% of the total - $3,000 - may be used for engineering studies, the balance being reserved for financial and legal brokerage activities. Any additional costs are the responsibility of the proponent.

All consultants participating in the program must be pre-qualified, i.e. they must demonstrate to the Ministry that the personnel involved have appropriate training and experience. We shall want to get together with this group frequently to review small hydro development problems and solutions.

b) Northern Programs: As noted above, the Ministry's program to date has had major impact in southern Ontario and for grid-connected systems, but relatively little impact in the north and for off-grid systems. This is odd when one

considers that off-grid power costs are about ten times higher, but probably refects the difficult logistics and the financial and regulatory uncertainties of operations in the north.

The northern program was conceived along the same lines as the previous demonstration programs. It is an attempt to 'jump start' the off-grid market by lowering risks to the first few of 'pioneer' projects, to establish experience and precedents in off-grid small hydro and to provide public examples of successful projects.

The northern program offers grants of up to 30% of eligible capital costs for commercial and industrial enterprises presently dependent on diesel-electric generation.

c) Industry Development: The small hydro industry, including manufacturers, engineers and development organizations, has enjoyed rapid growth over the last 5 years. Though still small, its viability in the marketplace is established.

The problem now is to keep up the momentum and to continue expanding in both domestic and export markets. The new Industry Development Program is intended to support worthwhile industry-initiated projects leading to cost reduction and/or market expansion.

Technological projects could involve, for example, development of improved design methods, testing and development of new turbines, improvements to electrical generators or controls, modularization and standardization of equipment, or improvement to production equipment and methods. Market-oriented projects could include assessment or reconaissance of specific markets, proposal preparation or export promotion. It is up to the industry to propose worthwhile projects.

We will favour projects with clear objectives and benefits, a high degree of cost-sharing and an appropriate linkage of available resources. This means that the skills and resources of our universities, utilities and government agencies such as the Ministry of Industry, Technology and Trade Development or Canadian International Development Agency should be utilized.

To help get this program underway, we will be working this year with the industry and other players to develop an overall strategy for industry development.

d) Information Transfer: This is where our program has been least effective, so we have recently begun to overhaul our efforts in this area. We can categorize the information activities as either technical, market or public oriented.

The plan for technical information is to standardize reporting formats, to computerize reference data and to establish frameworks within which new technical information can be readily accommodated, understood and transferred.

Standardized formats relate to reporting under our Site Development Assistance and Northern Small Hydro Programs. Standardized reporting of hydrological information facilitates the development of site inventories, while standard reporting of costs facilitates economic analysis and the development of estimating data.

We are presently consolidating all available information on small hydro sites in file at the ministry and developing a computerized index and summary of essential data. Instead of publishing an inventory, we are maintaining a database of site information which will be augmented and updated through our other activities. This database will be publically available.

Finally, we are using courses and seminars to create a framework for technical information transfer. The small hydro engineering course held in conjunction with this conference is an example of this approach. Given the success of the course, we are looking at undertaking similar projects to serve the needs of developers and operators.

Market communications has the objective of promoting Ontario's small hydro industry and encouraging sales in domestic and export markets. The Natural for Ontario brochure and the video version prepared for our conference display are an example. We will be working on improving these products and preparing new materials for export market promotion over the coming year.

Public information needs are also served by the "Natural" series, as well as the Streams of Power publication, but there is need for more focussed effort. The most important item for this year will be in the environmental area.

The public has justifiable apprehensions about the environmental impacts of small hydro development. As the volume of small hydro activity continues to grow, it is important that we establish a dialogue with those who share our concern for environmental protection. To this end, the Ministry will sponsor a workshop on the environmental impacts of small hydro this year.

e) Advocacy: As the Minister explained in his banquet speech, the role of the Ministry of Energy is to advocate small hydro development. All of the programs and activities described above are meant to serve this end. In addition, the ministry provides assistance on request in individual cases.

This role is behind the scenes and not as visible as demonstrations or grant programs. It has included representations to the Federal government on such matters as the tax treatment of Small Hydro and Parks Canada policy for small hydro development on the Heritage canals. Some areas we are currently working on are power purchase agreements and property tax assessment of private small hydro plants. All of these cases began with someone coming to us for help in solving a problem.

The purpose of advocacy is to help to resolve legal and institutional issues encountered by the small hydro industry. The issues must be sufficiently general for this role to be justified i.e. they should not be unique to a single proponent. Advocacy is not meant to reduce or replace a developer's normal responsibilities, but is rather meant to assist those who are being treated unfairly or arbitrarily to plead their case.

PROSPECTS FOR SMALL HYDRO

Since 1980, approximately 5 MW of new small hydro capacity has been commissioned in Ontario. Another 65 MW, however, is known by the Ministry to be under serious consideration for development. This gives confidence that the small hydro market will continue to expand and that 50-100 MW of new small hydro will be commisioned over the next 10 years.

The impact of 100 MW of small hydro is an investment of some $350 million in communities around Ontario, and predominantly for Ontario-produced goods and services. In grid-connected systems, we would expect to add approximately 700 million kWh/year to our electrical supply, worth about $15 million/year at current buyback rates. In the North, off-grid systems could generate 176 million kWh, much of this as new energy, worth some $52.8 million annually compared to diesel generating costs.

For Ontario's small hydro industry, the development of 100 MW over the next 10 or so years yields an annual domestic market in the range of $25-50 million.

Finally, in the export area, given that our products and services are highly competitive, there is no reason why we should not increase small hydro exports 10-fold to $150 million annually over the next 5-10 years.

CONCLUSION

Clearly, after 5 years, we have arrived at the end of the beginning. The prospects for small hydro are bright, and Ontario's small hydro industry is well-positioned for growth. Through the continued partnership of private initiative and supportive public policy, we 'help Ontario depend on herself, and the world depend on Ontario'.

Ian R. Lewis is Senior Advisor, Industry at the Ontario Ministry of Energy, with responsibility for the Ministry's small hydro program. Mr. Lewis has been with the Ministry of Energy since 1981.

SMALL HYDRO APPROVALS PROCESS

John Morton
Ministry of Natural Resources

My job this morning is to explain the small hydro power sites approvals process. As you know, private sector development of small water power sites is being encouraged by the Ontario Government.

Cabinet has directed the Ministries of Energy and Natural Resources to coordinate the preparation and implementation of an overall program to encourage small hydraulic development including the streamlining of an approval process.

One of the first steps the Ministry of Natural Resources has undertaken is a comprehensive survey of potential hydro electric resources at existing dams in the Province of Ontario. As a result of this survey, sites with the greatest potential will be offered for development in the near future.

Because water power development usually involves Crown lands under the administration of M.N.R., this Ministry has a major role in the program including that of ensuring that proposed developments are fully reviewed, both internally and publicly before being offered for disposition.

A. CROWN LAND SITES WITH NO EXISTING FACILITIES IN PLACE

APPROVALS REQUIRED - FIRST COME, FIRST SERVED

1.	Site Location by M.N.R. and Conservation Authority if applicable	- Lakes and Rivers Improvement Act - Conservation Authority Act
2.	Works approval by M.N.R. 6 to 12 months to submit Engineering Specs.	- Lakes and Rivers Improvement Act
3.	Exemption by Transport Canada should not be a serious problem as sites will normally impede navigation in their natural state.	- Navigable Waters Protection Act
4.	Water Taking Permit by M.O.E.	- Ontario Water Resources Act 50,000 litres per day
5.	Building Permit by Municipality if applicable	- Municipal Act
6.	Issuance of Licence of Occupation for Head Pond and Water Power Lease Agreement for facility or the works.	- Public Lands Act

We will talk about Licences of Occupation and Waterpower Leases in some detail a little later.

GENERAL

(a) Once approvals are obtained, proponent has 24 to 36 months to put the site into water power production. Time frame is at the discretion of the District Managers and Regional Engineer depending on the complexity of the development.

(b) A land rent will be charged for the site occupied by the works. However, waterpower rentals will be waived for the first 10 years of energy production, after which the prevailing water power rates would be used.

(c) Should the District Manager decide that the project would cause a "major" environmental impact, then no disposition will take place until all requirements of the Ministry of the Environment have been satisfied, which is a requirement under the Environmental Assessment Act.

CROWN LAND SITES WITH FACILITIES (E.G. DAM) IN PLACE

1. All sites will be advertised in local newspapers, and for a minimum of four weeks in the Ontario Gazette inviting proposals to develop sites.

2. Development proposals may be initiated by either a proponent or an M.N.R. District Manager.

APPROVALS REQUIRED

1. Site location by M.N.R. and Conservation Authority if applicable	- Lakes and Rivers Improvement Act - Conservation Authorities Act
2. Works approval by M.N.R. 6 to 12 months to submit Engineering Specs.	- Lakes and Rivers Improvement Act
3. Water Taking Permit by M.O.E.	- Ontario Water Resources Act 50,000 litres per day
4. Building Permit by Municipality if applicable	- Municipal Act
5. Issuance of Licence of Occupation for Head Pond and Water Power Lease Agreement for Works	- Public Lands Act

GENERAL

(a) Once approvals are obtained, proponent has 24 to 36 months to put the site into water power production. A land rent will be charged for the site occupied by the works. However, water power rentals will be waived a full year for each $100,000 spent by the proponent on restoration and development, after which the rate agreed upon in the initial offer will be used.

CROWN LAND RIVER BED SITES WHERE BANKS ARE OWNED BY PRIVATE INTERESTS

A development proposal is acceptable if:

(I) The proposal is from the land owner himself, or

(II) The proponent submits, with his proposal, a written statement from every land owner involved to the effect that the proposed development is concurred with and satisfactory arrangements for use of the private land have been arrived at.

APPROVALS REQUIRED

1.	Site location by M.N.R. and Conservation Authority if applicable	- Lakes and Rivers Improvement Act
2.	Plan approval by M.N.R.	- Lakes and Rivers Improvement Act
3.	Exemption by Transport Canada	- Navigable Waters Protection Act
4.	Water Taking Permit by M.O.E.	- Ontario Water Resources Act
5.	Building Permit	- Municipality

CHARACTERISTICS OF A WATER POWER LEASE AGREEMENT

1. Water power privileges are granted by the Ministry of Natural Resources under authority of Section 39 of the Public Lands Act. They are registered in Land Titles Offices, and therefore provide good collateral for financing.

2. The term or duration of a Water Power Lease Agreement is negotiable. Normally they are issued for 10-year periods with rights of renewal for four additional 10-year terms, so in effect you have a 50-year lease.

3. A Water Power Lease conveys a leasehold right to the land over which water flows. The leaseholder has the right to the water powers that can be generated from the difference in height of the water entering and leaving the leased lands. The leaseholder also has rights of exclusive possession and can control tresspass.

4. Rent is calculated:

   By the amount of electrical energy produced. The formula for calculating energy produced is adjusted annually according to the consumer price index. The current rate is approximately $5.70 per annual average horsepower or $7.65 per average annual kilowatt. If Ministry facilities are being leased, a percentage of gross income is also negotiated. The above rental structure appears after the waiver period.

5. Payment of municipal taxes by leaseholder.

6. Leaseholder responsible for repair and maintenance of facilities developed.

7. Indemnifies the Crown from all suits, actions, etc., arising from the development of the site.

8. Site must be developed and produced to its maximum capability to produce electrical power.

9. Lease may be assigned or sublet.

10. Any disagreement over the terms and conditions of the lease will be subject to arbitration under the Arbitrations Act.

11. Some provision or disposition of works.

GENERAL

Tenure from M.N.R. will in all probability be limited to a Water Power Lease Agreement for the Bed of the River only. No Licence of Occupation will be required if head pond or flooding is confined to the property owner's land.

HEAD POND

The types of tenure that is granted to a proponent wishing to develop a low head power site is a Licence of Occupation to cover the head pond or reservoir that will be flooded upstream from the dam site. Licences of Occupation are similar in some respects to an easement and authorize the development to flood an area of land to a pre-determined contour of elevation agreed upon by the Ministry of Natural Resources.

MNR selects the best proposal on the basis of:

(A) The engineering acceptability of the proposal;

(B) The amount of money the proponent offers to pay for the use of the Crown land involved, including any existing Crown owned facilities (e.g. a dam) on the land;

(C) The most efficient use of the water resource for power development.

(D) The degree to which the proposal considers or mitigates any social conflicts.

(E) The proponent's financial ability and expertise in developing small hydro sites.

That concludes the approval process required to develop small hydro sites. While it may seem to be an onerous task, Ministry staff are committed to streamlining the process as much as possible.

BIOGRAPHY

John Morton joined the Ontario Government in 1955. He has worked in most major divisions of the Ministry of Natural Resources and is now the Supervisor of Public Lands for the Province. Most of his career was in Northern Ontario, with the last 9 years in Queen's Park.

Mr. Morton is a Resource Technician who was born and educated in England.

Ministry of Natural Resources
Ontario

Subject		Policy No.	New
Small Hydro Power Sites		LM 8.08.01	☐
Compiled by - Branch	Section	Date Issued	
Land Management Branch	Public Lands	86-03-13	
Replaces Directive Title	Number	Dated	Page
Small Hydro Power Sites	LM 8.08.01	June 1, 1983	1 of 7

Private sector development of small water power sites is encouraged by the Ontario Government.

Water power development usually involves Crown land under the administration and control of the Ministry of Natural Resources. This Ministry has the responsibility of ensuring that proposed developments are fully reviewed with regard to the concept of integrated resource management before being offered for disposition.

"Small hydro" means any site with a power potential of less than 20 megawatts (20,000 kilowatts or 20,000,000 watts). Regardless of who initiates interest in a potential water power site, Ontario Hydro has a non-statutory right of first refusal for any site that has a potential average energy capacity greater than 20 megawatts. Where a party other than Ontario Hydro indicates an interest in developing a site of 20 mw+, Ontario Hydro is to be allowed 3 months within which to exercise its right of first refusal. The right is exercised by submitting to M.N.R. a schedule for expeditious investigation and/or development of the site. If Ontario Hydro does not exercise its right of first refusal, it will be treated like any other potential proponent when it comes to offering a site (one with existing facilities) for public competition. If Ontario Hydro responds to any public invitation, it does so on the same basis as any other proponent, except that where development by others might impinge upon Ontario Hydro's interests in other facility or potential project, Ontario Hydro has the right to intervene by filing a statement of its objections with the Ministry of Natural Resources.

Potential Sites fall into 3 categories:

1. Crown land sites with no existing facilities in place.

2. Crown land sites with facilities (e.g. dam) in place.

3. Crown land river bed sites where banks are owned by private interests.

The following operational policy will guide the processing of applications and the disposition of sites:

1. CROWN LAND SITES WITH NO EXISTING FACILITIES IN PLACE

(a) Proponents will be treated on a "first come, first served" basis.

(b) "First come" shall be interpreted as initial application for location plan approval under the Lakes and Rivers Improvement Act which may be submitted to the appropriate office of the Ministry of Natural Resources.

(c) Sites will be examined by District Managers with Regional Engineering staff to determine availability for small hydro development with a view to multiple land use and environmental impact. The assessment will consider all aspects of integrated resource management.

(d) Assuming all integrated resource management constraints can be mitigated and the project does not constitute a major impact on the environment, the District Manager will approve the location and advise the proponent that he has a certain time period during which he must do a feasibility study and submit to the engineering staff plans and specifications, including detailed construction drawings, for "approval of works" under the Lakes and Rivers Improvement Act. This period would be up to twelve months and is set by the District Manager according to the complexity of the project.

(e) If the proponent decides that the site is economically feasible to develop and the "approval of works" is forthcoming, a deposit will be taken from the proponent equivalent to $5 per kilowatt of estimated power production. The proponent has a period of time up to 36 months from the date of approval to put the site into water power production. If after this period of time, which is set by the District Manager at his discretion, the site is not in operation, the proponent's interests may be cancelled, at the discretion of the Minister, and the deposit forfeited.

(f) During the development period, the proponent will perform a legal survey of the site and enter into a water power lease agreement with the Ministry.

(g) A land rent will be charged for a site occupied by the works, however waterpower rentals will be waived for the first 10 years of energy production, after which the prevailing water power rates would be used.

(h) A land rental amount would be a percentage of the market value of the site as determined by the various means at the disposal of the District Manager.

(i) In the event of a disposition to a private sector applicant, should the District Manager decide that the project would cause a "major" environmental impact, then no disposition of Crown resources can take place until the Ministry of Environment has determined whether or not an Environmental Assessment is required.

2. CROWN LAND SITES WITH FACILITIES (e.g. DAM) IN PLACE

(a) Development proposals may be initiated by either a proponent or a District Manager.

(b) The site will be examined by the District Manager with Regional Engineering staff to determine availability for small hydro development in consideration with all aspects of integrated resource management and the field environmental assessment process. In effect, all program constraints will be identified and recommendations made on how these might be overcome.

(c) Interested parties are then invited through the various media and the Ontario Gazette, to come forward with development proposals. Advertisements are to be run at least one per week for four weeks.

2. Crown Land Sites with Facilities (e.g. Dam) in Place (cont'd)

(d) The District Manager will provide prospective proponents with proposal packages conveying all known information about the site. These packages will include operating and/or management constraints as well as restoration requirements with which the successful proponent must comply.

(e) The successful proponent must submit plans and specifications, including detailed construction drawings, to the engineering staff for "approval of works" under the Lakes and Rivers Improvement Act, and obtain any other approvals required within 12 months of the proposal being accepted, the time being set by the District Manager at his discretion according to complexity of the project.

(f) At the time of "approval of works" of the project, a deposit will be taken from the proponent equivalent to $5 per kilowatt of estimated power production. The proponent then has a time period of up to 36 months to put the site into water power production. If after this time period, which is set by the District Manager, the site is not in operation, the proponent's interests may be cancelled at the discretion of the Minister, and the deposit forfeited.

(g) During the development period the proponent will perform a legal survey of the site and enter into a water power lease agreement with the Ministry.

(h) A land rent will be charged for the site occupied by the works, however water power rentals will be waived a full year for each $100,000 spent by the proponent on restoration and development, after which the standard water power rate, incorporating the consumer price index, will be used.

(i) The upset price to be used for examining proposals would comprise a land rental determined much the same way as in 1(h), the energy charge becoming effective when the waived period, if any, is ended.

3. CROWN LAND RIVER BED SITES WHERE SHORELINES ARE OWNED BY PRIVATE INTERESTS

(a) Owners of shoreline will be given first right of refusal to develop the site for small hydro.

(b) If owners of the shoreline express no desire to develop the site, options 1 or 2 will apply where applicable, subject to the proponent acquiring an interest in the adjacent lands necessary for access and development purposes.

4. GENERAL

(a) Every proponent is to be made fully aware of his sole responsibility for the safety and maintenance of the proposed facility and his liability in the event of accidental damage.

(b) Every proponent should also be made aware of all the approvals that may be required; which are:

- approval from Transport Canada under the Navigable Waters Protection Act, if the waterway is deemed navigable.
- approval from Fisheries and Oceans Canada under the Canadian Fisheries Act, if migrating fish are involved.
- approval from local Conservation Authorities if applicable.
- permit to draw water from the Ministry of the Environment Ontario if more that 50,000 litres per day.
- building permit from municipality if area is incorporated.
- approval of electrical equipment under the Electrical Safety Code administered by Ontario Hydro.

(c) No developer will be allowed to develop more than three sites at any given time.

(d) All water power sites are liable for tax assessment under either the Assessment Act, if the site is in an organized municipality, or the Provincial Land Tax Act if it is not. In some cases the Assessment Act can apply if the site is outside an organized municipality but is still subject to a school board tax levy. The Provincial Land Tax assessment is for purposes of Provincial Land Tax, local roads board levies and local service board levies. The assessments are usually based on the market value of the facilities and improvements although some exemptions are made under the Assessment Act for the machinery used for power generation. The way of arriving at the market value can vary between the two acts. Generally, the structural costs are used under the P.L.T.A. while the ability to produce revenue is used under the A.A. Each case can be different and is usually considered on the basis of its own merits. Information can be obtained from the Regional Assessment Commissioner of the Ministry of Revenue.

(e) Occupation of Crown lands for purposes of transmission lines and/or headpond flooding would be authorized under the Public Lands Act by land use permit and/or licence of occupation and would entail a separate renting calculation.

(f) Every proponent should be advised that in the event the project constitutes a major impact on the environment, the costs of an environmental assessment are to be borne by the proponent.

(g) In connection with the evaluation process used for public competition for sites, the examining committee will comprise the District Manager, District Land Supervisor and District Accountant all of the M.N.R. District within which the site is located, plus an M.N.R. Regional Engineer and a representative from the Ministry of Energy. The selection criteria includes:

    (a) The engineering acceptability of the proposal;

    (b) The amount of money the proponent offers to pay for the use of the Crown land involved, including any existing Crown owned facilities on the land;

(c) The most efficient use of the water resource for power development;

(d) The degree to which the proposal considers or mitigates any social conflicts;

(e) The proponent's financial ability and expertise in developing small hydro sites.

OTHER CANADIAN JURISDICTIONS

AN OVERVIEW OF FEDERAL ACTIVITIES AND POLICY

T. P. Tung and J. C. Barclay
Energy, Mines and Resources Canada

1. INTRODUCTION

To date, Canada has 54,900 MW (EMR, 1984) of installed hydroelectric capacity, representing two-thirds of total electricity generation. The provinces of Quebec, British Columbia and Manitoba produce most of their electric power from large hydroelectric stations.

There are more than four hundred hydro stations (Statistics Canada, 1983) in Canada owned by utilities and companies. A fifth of the stations have an installed capacity of 100 MW or more, yet they provide 9[illegible]% of total hydro capacity. On the other hand, more than half the total number of stations have an installed capacity of less than 15 MW, and these represent only about 2% (950 MW) of the total hydro capacity in Canada. However, most of the hydro stations in Canada, including some larger scale projects, are low-head stations under 40 MW. This is due to the relatively low relief in many regions except for the Canadian Rockies and the Coastal Mountains in British Columbia.

Due to a slower than expected load growth over the past several years, most Canadian utilities presently have significant surpluses of generating capacity. It is expected that hydro power development will continue to expand well beyond the year 2000, but mainly from large-scale projects far from load centres. The uncertainty in load growth rates has caused some utilities to consider installation of generating capacity in smaller increments to provide greater economic flexibility. To a limited extent, medium-scale low-head and small scale hydro projects could be considered as supply options because of shorter lead times and their ability to more easily match smaller changes in system demand. The challenge is for these projects to demonstrate cost competitiveness within the available mix of generation options, and for Canadian utilities to recognize and encourage these smaller scale options. As well, there are significant opportunities for small scale hydro in remote locations which currently rely on expensive diesel-electric power generations.

In recent years, the Canadian Government has supported the development of small scale and low head hydro power sources through a variety of initiatives including inventory and feasibility studies, research and development activities, demonstration programs, and tax incentives. Some of these measures are the subject of general and specific agreements with provinces and provincial utilities, while other activities reflect federal action to fill an identified gap or a traditional role. The purpose of this paper is to describe briefly the small hydro scene in Canada and to introduce several technical, economic and institutional issues affecting small hydro development as viewed from a Canadian perspective.

2. SMALL-SCALE AND LOW-HEAD HYDRO POTENTIAL

2.1 SMALL HYDRO POTENTIAL

It has been estimated that there is a theoretical potential of 2,000 MW at more than 1,000 sites of less than 10 MW in scale. Some potential has been identified in most of the provinces for both grid-connected and remote service applications. The largest potential has been identified in Ontario, British Columbia and Quebec, with significant potential in New Brunswick and Nova Scotia as well. The provincial distribution of this potential is shown in Figure 1. While it has been shown that many of these sites are technically and economically feasible to develop, a consistent estimate of developable potential in Canada has not been produced.

2.2 INVENTORY STUDIES

A number of federal and provincial studies of small hydro potential have been undertaken in recent years. While the variations in methodology and technical, economic and environmental constraints suggest that the estimates of potential should be treated with caution, the data nevertheless indicate the availability of a valuable potential energy resource. The following summary briefly describes these study results.

Quebec -- Studies (Hydro-Quebec, 1980) have shown there are 312 sites of less than 100 MW capacity totalling 5,222 MW of potential. There are also 300 smaller rivers which have a total potential of 4,764 MW. Of the 312 sites, there are 182 sites less than 15 MW capacity with a total potential of 946 MW. There are 120 sites of less than 5 MW capacity each for a total potential of 260 MW; 24 of these sites are at existing dams with 27 MW in total potential.

Ontario -- The potential for new site development in the 2 to 10 MW scale (Ont. Hydro, 1982) is 57 sites totalling 238 MW of capacity. The potential for sites of less than 2 MW is estimated to total 409 MW, while there are also more than 220 private, decomissioned small power or mill sites, most less

1 MW in scale (Ont. Hydro, 1976). A new "List of Water Powers in Ontario" (Ont. MNR, 1983) has identified 550 formerly developed sites which may have redevelopment potential, and an inventory of small hydro potential at existing publicly-owned dams has also been completed. In summary, it is generally quoted that Ontario's potential of small hydro resource amounts to some 500 MW (Moore, 1984).

British Columbia -- It is estimated there are 222 micro and mini-hydro sites totalling about 14 MW (Crippen, 1980) near non-B.C. Hydro remote diesel-power communities. Most of these are micro-hydro sites less than 100 KW in scale. There are 665 sites in the 100kW to 20MW range for a total capacity of 1,439 MW, most of which could be grid-connected. Of these, 54 sites with a total installed capacity of 300 MW can be economically developed, while 8 B.C. Hydro diesel-power serviced remote communities can be supplied with small hydro power (B.C. EMPR, 1984). An inventory study by B.C. Hydro on Vancouver Island identified 37 sites between 1 to 20 MW which were free from environmental constraints. Eight appear to be economically feasible and their combined capacity is about 60 MW (B.C. Hydro, 1983).

New Brunswick and Prince Edward Island -- A study carried out in 1983 (Monenco, 1984) identified 154 sites in New Brunswick in the range of 1 to 20 MW and 6 mini-hydro sites in Prince Edward Island as "potentially available" sites. Final screening identified 52 "environmentally compatible and potentially practical" sites in New Brunswick with a total potential of 340 MW. It is expected the micro and mini-hydro potential from existing dams in N.B. could also provide some economic projects.

Nova Scotia -- An earlier federal water power resources inventory (EMR, 1964) identified more than 50 sites with potential less than 10 MW totalling more than 160 MW in capacity. In recent years, studies by Nova Scotia Power Corporation have identified more than 18 small hydro projects which could provide 80 MW in total capacity. Seven of these projects are judged to be economically feasible.

Newfoundland -- An inventory study funded by the federal government (Shawmont, 1979) identified 83 sites ranging from 30 KW to 8 MW for remote communities. There is potential for mini-hydro development within close proximity to 27 of the 39 diesel-generating plants. Economic analysis indicated that mini-hydro development is probably viable for fuel displacement in 9 of these communities. There are several small hydro sites in the range of 5 to 15 MW which have been evaluated by the provincial utility.

Prairie Provinces and Northern Territories -- In Manitoba, Saskatchewan and Alberta, excluding the many medium to large low-head sites, there are at least 47 sites of 1 to 10 MW

identified (EMR, 1964) with a total of 237 MW in capacity. In the Yukon and Northwest Territories, there are many medium to large low-head as well as small hydro sites. These potential sites are too distant from communities and the site potential is often too large for the communities' load demand. Recent federal Remote Communities Demonstration Program studies have identified some mini-hydro sites closer to the communities.

2.3 MEDIUM TO LARGE-SCALE, LOW-HEAD HYDRO POTENTIAL

Preliminary estimates indicated that Canada has more than 66,000 MW of hydroelectric potential which is technically and economically (at-site) developable. Most of these sites are large capacity, greater than 100 MW; some are in the range of 10 to 100 MW. Of this potential, some 20,000 MW falls into the category of low-head, i.e., less than 40 MW. Low-head installations generally are run-of-river plants and have environmental advantages over high head storage plants. However, their unit cost per kilowatt is usually higher than high-head plants simply because of the larger turbine sizes they require to accommodate large flows. A challenge is to develop innovative techniques in design, generation and transmission (Bateman, 1983) in order to reduce costs.

In addition to the foregoing low-head river-hydro potential, it is estimated there is more than 5,500 MW of undeveloped tidal power capacity in the Bay of Fundy. A study has indicated that the selected tidal power schemes could be economically attractive if improved design and construction techniques are used (TPC, 1982). A considerable amount of research work has been done on the environmental implications of Bay of Fundy tidal power development (Daborn, 1985). Both beneficial and adverse environmental impacts could be produced by the different tidal power sites and schemes. It is believed that by developing appropriate design and operating strategies the adverse impacts can be mitigated and reduced.

2.4 SMALL HYDRO AND REMOTE COMMUNITIES

There are some very good opportunities for small hydro developments to serve off-grid communities. The displacement of expensive diesel generation in remote communities could be the most economically feasible application for small hydro. In British Columbia, where most sites are high-head, eight of the 13 large communities with diesel generation stations operated by B.C. Hydro have identified small hydro sites. Preliminary estimates indicated that these could be developed at an average cost less than the cost of diesel fuel. A recent federally funded study (Sigma, 1983) indicated that of 92 communities surveyed, 68 are interested in small hydro power. Most of these are mini and micro-hydro sites located on the southwest coast and on Vancouver and Queen Charlotte Islands. In other provinces, such as Northern Ontario, Newfoundland and Labrador, Northwest Territories and Yukon, some communities have economically developable small hydro sites and feasibility studies have been undertaken.

3. FEDERAL SUPPORT FOR RESEARCH, DEVELOPMENT AND DEMONSTRATION

3.1 INTRODUCTION

The Government of Canada began its support for research and development into alternative energy technologies following the first oil price shock in the early 1970's. This support was expanded in 1977 to include demonstration activities with the announcement of the CREDA Program. The National Energy Program (1980) significantly increased the level of federal resources going into renewable energy R&D. Federal support for renewable energy demonstrations was reaffirmed in 1983, and recently, the federal government has announced a renewed commitment to renewable energy R,D&D. The following sections summarize the results achieved to date from the small and low-head hydro R,D&D activities supported through these program initiatives.

3.2 RESEARCH AND DEVELOPMENT ACTIVITIES

Within the federal Renewable Energy R&D Task, several activities to support industry and inventors on small-scale and low-head hydro, including tidal technology development, have been conducted under the Hydraulic Energy R&D program:

3.2.1 SUPPORT FOR TURBINE MANUFACTURERS ON PRODUCT DEVELOPMENT AND TESTING

The National Research Council has developed a turbine test facility to assist Canadian turbine manufacturers and inventors to develop new, novel and more competitive machines. To date, several small turbines, all of the propeller-type, using tangential flow inlets to achieve swirl, have been tested for Galt Energy Systems Ltd., Cambridge, Ontario. This low-cost, but very efficient turbine has now been installed at ten sites in power outputs ranging from 20 to 500 kW.

3.2.2 DEVELOPMENT OF A DARRIEUS TYPE VERTICAL AXIS HYDRAULIC TURBINE (VAHT)

Since 1979, the Hydraulics Laboratory of National Research Council has carried out model testing and has contracted field testing to develop a Darrieus-type hydraulic turbine capable of extracting kinetic energy from fast river and tidal currents. Nova Energy Ltd. of Dartmouth, Nova Scotia designs, builds, installs and tests the field units (Davis, 1983).

Several prototype models have been developed and tested at different sites. A 2.4 m diameter VAHT was field tested in 1.5-2 m/s currents in the St. Lawrence River at Cornwall, Ontario during 1983 and 1983 (Figure 2). It produced between 4 and 5.2 kW depending on design configuration and flow rates at a 33-34% rotor efficiency. Installation equipment proved to be costly at this site. A lighter and easier-to-install VAHT, having a capacity of a few kW, might find an application in the

remote areas where expensive diesel-generated electricity is the only supply alternative.

Figure 2. Pontoon-supported and Ducted VAHT at Cornwall (Courtesy of National Research Council Canada)

The VAHT is also suited to an ultra low-head application (less than 2 m) where higher velocities through the machine may be achieved. The turbine could be installed in an opening of an existing low dam, or at a flow regulating gate. A 1.8 m diameter-ducted VAHT was constructed and installed in 1983 at a sluice gate of the existing low dam on the East River near Sheet Harbour, Nova Scotia. Extensive initial tests, however, revealed certain structural and design deficiences in the underwater bearing, and in vibrations of the entire machine. The machine has been rebuilt by the contractor and is now running smoothly.

Present field trials show the need for continuing laboratory and field tests to improve certain aspects of the mechanical and hydraulic performance, mooring and installation (Faure, 1984). Although field tests have shown the VAHT efficiency is not high (35% to 60%), its use of very little material (3 to 5 slender hydrofoils) to sweep large flow cross-sections shows promise of economic exploitation if installation costs can be reduced. It is well-suited to the near zero-head, damless, open river and tidal sites, and tidal current sites in the Bay of Fundy and coastal British Columbia are potential application areas. For tidal or ocean current applications, Nova Energy Ltd. recently built a completely submerged VAHT and generator. It has been tested in ocean currents off Florida for a U.S. client.

3.2.3 DEVELOPMENT OF INNOVATIVE DESIGN AND ASSESSMENT TECHNIQUES

Studies on hydrologic design methodologies for small-scale hydro at ungauged sites have been carried out for the past two years. Application manuals and computer programs have been developed. These provide guidance for determining design flows and flood or current magnitudes at small hydro sites without involving costly studies. Methodologies involve developing regional flow duration curves and "turbinable flow" curves by

relating characteristics of curves to physiographic and climatic parameters (Judge, 1985). In a feasibility-level study for the Atlantic Provinces, synthetic daily flow sequence data were generated for potential sites, and energy and revenues were estimated by computer simulation (Acres, 1985). In the Province of British Columbia, studies are being undertaken using watershed modelling techniques.

The EMR Conservation and Renewable Energy Office in British Columbia is finalizing the editing of a manual for do-it -yourself small hydro design. This manual was produced by over seven consultants who were each responsible for researching and writing one or more chapters of the manual. The manual addresses the subject of assessing preliminary feasibility, technical design, how to obtain permits, licenses and discussion on legal aspects, as well as the economics and financing, and getting started. It is expected that this manual will be available in the summer of 1986.

A user-friendly micro computer program for costing small hydro is being prepared by consultants for EMR. The computer program "SHYDRO" will be available to the public and can be integrated with hydrology programs already developed to estimate the cost of twelve components of potential hydro development.

3.2.4 TIDAL ENERGY R&D

At the Hydraulics Laboratory of the National Research Council, a hybrid tidal model has been developed which coupled a physical model of a small part of the Bay of Fundy to a numerical model of the rest of Fundy out to the Continental Shelf. This pilot hybrid model developed the tools to allow construction of a detailed physical model of the local area of interest for a tidal power barrage. Thus, flow patterns near the powerhouse and sluice gates, tidal amplitudes, and sediment deposition or erosion may be studied at a practical scale without requiring a physical model of the whole of the Bay of Fundy and Gulf of Maine.

Meanwhile, a numerical three-dimensional hydro-dynamic model for the Cumberland Basin of the Bay of Fundy is being developed by consultants for EMR. This model will identify the principal processes responsible for the current patterns. It will be able to examine the tidal barrier-induced modification to the tidal regime and the circulation patterns under various possible operational scenarios.

The concept of an ultra low-head approach to tidal power has recently been put forward (Simons, 1984). The concept involves a "tidal fence", analogous to a bridge across high-velocity tidal currents in a deep channel. However, its engineering detail and economic feasibility remain to be determined (Highquest, 1985).

Since important environmental factors related to Bay of Fundy, tidal power schemes have been identified, future R&D on tidal energy would likely aim toward developing techniques and control strategies so as to achieve an acceptable balance in the maximizing of energy output and the minimizing of environmental disturbances.

3.3 SMALL HYDRO DEMONSTRATION PROJECTS

Small hydro demonstration activities have intensified during the past few years with a number of significant achievements. For example, the 440 kW mini-hydro project at Roddickton, Newfoundland demonstrated simplified construction and installation techniques, as well as economic viability. The project has been interconnected with the existing isolated diesel system and is remotely controlled (EMR, 1983).

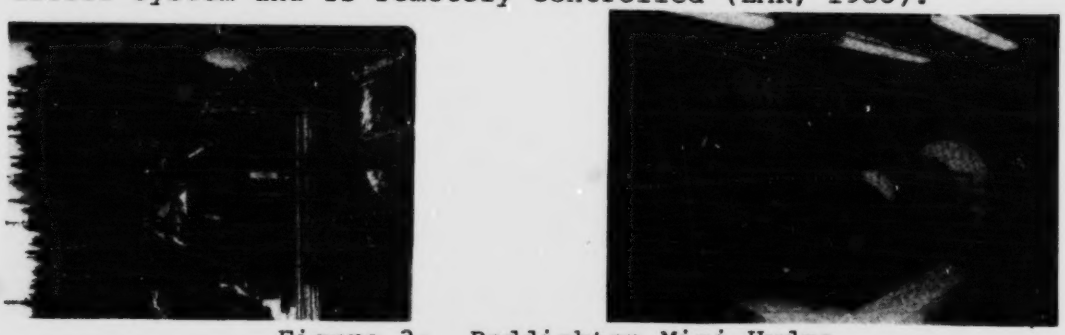


Figure 3: Roddickton Mini-Hydro
Construction of Timber Crib Dam and Interior of Powerhouse

Under the Federal/Provincial Conservation and Renewable Energy Demonstration Agreement (CREDA) Program, 16 small-scale hydro projects have received assistance towards total project costs of $5 million. These new or redeveloped facilities ranged in size from 2 kW to 2.5 MW and included projects from coast to coast. There were five projects in B.C. and one in the Yukon, aimed at the tourism, small industrial or agricultural sectors. Three projects have been completed in New Brunswick, including a 1 MW addition of low-head hydro at the City of Edmundston, and two micro-hydro (50 kW and 6.9 kW) for dairy and salmon farms.

In Ontario, the Canada/Ontario Small Hydro Demonstration Program, a sub-program of CREDA, has provided financial support totalling almost $800K as capital cost contributions to seven projects having a total generating capacity of 1,366 kW. The average contribution level to these projects was 33 percent, with total investment costs reaching about $2.4 million. The seven project proponents included two municipal utilities, a conservation authority, a private non-profit organization, an operating flour mill and two tourist mills. The capital cost for these projects ranged from $750 to $2800 per kW, and the project rates of return were estimated at 13-25 percent after grant compared to 8-17 percent before grant.

The purpose of this demonstration initiative was to test the financial viability of small hydro in Ontario while generating some industrial activity and putting some technical innovations into practice. Examples of innovative features of the Ontario demonstration projects are shown in Figure 4. In the Brantford project, the turbine runner was set above head water level. At Fanshawe Dam, the existing discharge tube from the dam was coupled to the steel penstock.

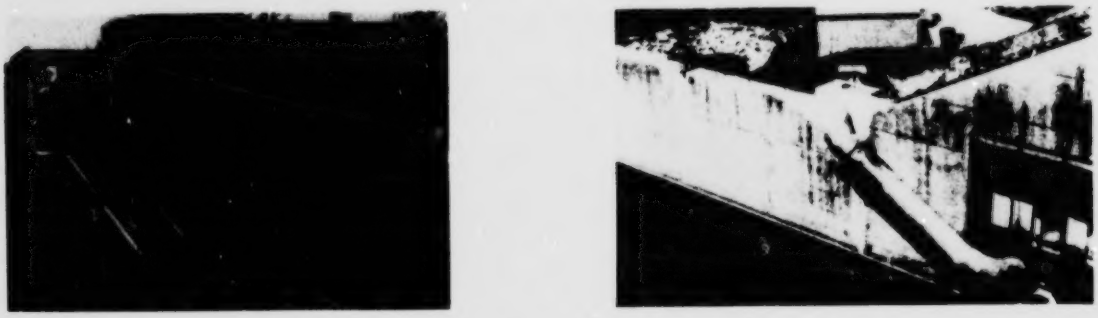


Figure 4: Brantford (left) and Fanshawe Dam (Right), Ontario

Under the study phase (Phase I) of the Remote Community Demonstration Program (RCDP), 19 small hydro feasibility studies have received financial assistance:

- six B.C. studies examined both high- and low-head opportunities, with at least one viable project in each category being identified;

- there are opportunities for near-term implementation of projects in Saskatchewan and Labrador communities;

- an encouraging finding of the study for Dawson City, Yukon, is that a rehabilitation of the Klondike North Fork hydro plant will cost only $6 million. It would include installation of two 1 MW units and could pay for itself in three years;

- in the Northwest Territories, six communities have been studied for small hydro potential. The study conclusions are that the Community of Coppermine could be supplied with electricity by a small hydro installation with 2 MW capacity (present peak load 620 kW). The project would involve no dam but rather an intercepting trough in the large- and high-flow Coppermine river. The remaining communities were found to have a low near-term potential.

Under the RCDP Phase II (demonstration phase), it is expected that there will be a limited number of demonstrations of small hydro projects.

With the assistance of the ENERDEMO program, in Quebec, four submersible turbo-generator units were installed at two retrofitted mini-hydro dams of the City of Coaticook. A 1 MW new low-head hydro plant was built and commissioned at the remote community of Wemindji, near James Bay.

3.4 ANNAPOLIS LOW-HEAD TURBINE DEMONSTRATION

On May 2, 1984 North America's first tidal power plant began producing power at Annapolis Royal, Nova Scotia, in the Bay of Fundy. It demonstrated the operation of the largest straight-flow turbine (7.6 m) with rim-mounted generator (STRAFLO).

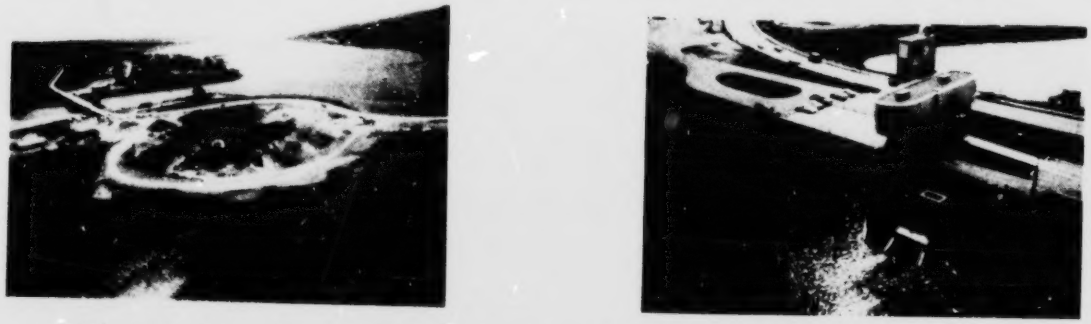


Figure 5: Annapolis Tidal Project During Construction and Completion

The 20 MW output plant produces approximately 50 GWh annual energy and its rated head is 5.5 m. The Federal Government contributed $25 million toward total project costs of $60 million. Because the modern Straflo turbines can be applied at the low-head sites up to 40 m, its compact layout will provide significant cost savings in civil structure over the vertical propellor units. Innovative powerhouse and intake design, shop pre-assembly of large pieces of turbine-generator equipment, automatic operation and remote control, and other features have been demonstrated at this landmark project. The Federal Government is participating in the monitoring of its performance. The satisfactory operation of this project could improve the economics of harnessing low-head river hydro resources in Canada and enhance prospects for development of major tidal power sites in the upper reaches of the Bay of Fundy.

4. RENEWED FEDERAL SUPPORT FOR RESEARCH, DEVELOPMENT AND DEMONSTRATION

In May 1985, the Minister of Energy, Mines and Resources announced a renewed commitment to energy conservation, transportation and renewable energy through the three-year National Conservation and Alternative Energy Initiative (NCAEI). This program provides $111 million for renewable energy research, development and demonstration activities. An additional $4 million per year was made available for renewable energy R&D as a result of the Federal Government's decision in July 1985 to extend the energy R&D program and support established priorities for economic renewal through emphasis on private sector initiative.

About one-half of the $12 million annual budget for renewable energy R&D will go towards bio-energy technologies, and about 8.3 percent of the amount remaining for other renewable technologies will go towards the support of hydraulic R&D

initiatives ($500K/year). The R&D program will require cost-sharing of projects with industrial performers who seek to develop new or improved products for near-term commercial exploitation.

As part of the R&D program, the hydraulic energy activities are expected to focus on developing techniques and technologies to economically exploit the small-scale and low-head hydro resources, including tidal energy. Although large-scale hydroelectric technology is well-developed and proven, there remains considerable scope for innovation and improvement not only of small and low-head hydro equipment, but also in the design and construction of civil work systems which can be quickly and easily adapted to a particular site. The December 1985 issue of the Department of Supply and Services Research and Development Bulletin carried a Request for Proposals under this program, with the following identified areas of technical interest:

(a) Development of low-cost and innovative civil and equipment system packages for micro/mini-hydro off-grid applications

(b) development, including model and field tests, of cost-effective generating equipment systems

(c) site assessment methodology, and computer models

In order to properly manage this work, a Technical Advisory Committee (TAC) has been established. The committee, with members from public and private industry, will provide expert technical advice, help plan program priorities, evaluate proposals, manage certain projects and direct program activities.

In addition to the R&D funding, NCAEI has made a limited funding level available to provide federal support for pilot projects, strategic demonstrations, remote community and innovative financing demonstration projects, and monitoring technology transfer activities. The available funding has not been allocated towards individual technologies.

5. ISSUES AFFECTING SMALL HYDRO DEVELOPMENT IN CANADA

The considerable experience in the small hydro area accumulated over the last eight years through RD&D project management has helped to identify several key issues which affect the viability of small hydro technology. The most important of these issues from a federal perspective is that of jurisdictional responsibility. In Canada, the responsibility for natural resource management, including the management and development of water resources, rests almost exclusively with the provinces. In turn, most Provincial Legislatures (except for Alberta and P.E.I.) have assigned responsibility for power development to Crown Corporations established through

facilitating legislation. These utilities have a mandated monopoly to supply and distribute electricity to consumers at the lowest possible cost. They are exempt from paying property taxes and provincial and federal income taxes, and they have the additional advantage of access to capital at preferred rates due to provincial government guarantees on their debt funding requirements. Many of these utilities have either right-of-first-refusal or exclusive responsibility for hydropower site development within their province.

The federal approach in this area must obviously be to fully respect the exclusive jurisdiction of the provinces, and this reality limits the federal role primarily to that of providing developmental support for new electricity-generation technologies such as small hydro. The exception to this situation is where a small hydro development might be contemplated in an area of federal jurisdiction, such as on Crown land, supplying federal facilities or located in the Yukon or Northwest Territories. In any of these circumstances, various federal policies, legislation and/or regulations could impact on small hydro development. These areas of federal responsibility have received increased scrutiny in the last few years and several institutional impediments have been identified which must be addressed.

Perhaps the most important issue affecting the viability of small hydro is the issue of appropriate power purchase rates for the output of these facilities. This issue has begun to receive increased attention in Canada as more and more small power production opportunities have been identified and as more has been learned about the U.S. experience with legislation known as PURPA (Public Utilities Regulatory Policies Act). This increasing interest prompted EMR to undertake a contracted study (Passmore, 1985) on the U.S. experience with the PURPA legislation and to examine the potential applicability of similar legislation in Canada.

The study found that the experience in the U.S. with PURPA has produced mixed results. Many utilities have tried to resist the primary purpose of the legislation which was to open up the market for power production. Many other utilities, along with their state regulatory authorities, have followed the spirit of the legislation and the power production activity generated as a result has had a significant impact on the utility's power planning. The leading example of the positive effects of PURPA (reinforced by federal and state tax credits) is in California, where the full spectrum of alternative generation technologies has been actively pursued.

By contrast, the study found that most Canadian utilities have established power purchase policies, but rates offered to independent power producers are not debated nor established in a public forum. In several jurisdictions, rates offered are based on avoided fuel costs only (e.g., from coal or oil-fired

plants), without allowance for capital costs due to the existing surplus supply capability. In other provinces, utilities will accept but not pay for surplus power generated, while a few Canadian utilities have established policies of net billing at retail rates, some with, and others without, payment based on avoided fuel costs for any surplus power supplied to the grid system.

Unfortunately, unlike the situation in the U.S., rates offered by Canadian utilities for privately-generated electricity do not approach retail rates. Individuals and companies with an interest in small hydro and other electricity supply options believe these rates are significantly below what would otherwise be the utility's true avoided cost, but there is no suitable public forum within provincial jurisdiction in which this issue could be properly debated.

This price and market access constraint on the marketing of the output from small power production projects, coupled with the advantages available to utilities of a tax exempt status and access to capital at preferred rates, places small power producers in Canada in a position of considerable competitive disadvantage.

6. CANADIAN SMALL HYDRO DEVELOPMENT POTENTIAL

The RD&D programs of the federal government, combined with the efforts of several provincial governments, particularly Ontario, have assisted in the development of a small hydro technology supply capability in Canada. The Canadian small hydro turbine industry's annual equipment sales has been between 20 MW to 30 MW in the past few years, representing a $20 to $30 million generating equipment business. Perhaps an equal amount of business has been generated in the engineering and civil construction stages, for a total of $40-$60 million. Several Canadian companies have proven their ability to service the kilowatt scale (up to IMW) market with both conventional turbines and support systems as well as with more innovative product designs. These companies, along with other individuals and financial interests, have successfully demonstrated their capability to develop small power production opportunities and have placed themselves in a position to further develop their technology and industrial capability.

The Government of Canada's new NCAEI Program will continue to provide federal funding support for research, development, demonstration and information and technology transfer activities in the conservation and alternative energy area. As previously noted, this program will include support for these activities as they relate to small and low-head hydro sources to further technology development and to address the identified market potential.

The general philosophy supporting this renewed initiative is

that government assistance is required to allow an immature industry to develop their products to the stage of commercial readiness. This approach is based on the premise that market forces will act effectively to determine the appropriate level of commercial activity.

While government-supported demonstration projects appear to be necessary as part of the commercialization process, an inference to be drawn from the preceding discussion and other observations is that these activities in themselves are not sufficient to ensure that commercial competitiveness in the domestic market place is achieved. Policy makers are confronted with the dilemma of how to ensure the realization of identified economic and industrial potential when a variety of factors are at work to produce poor financial returns.

To date, these problems have been approached on several fronts. Demonstration program efforts have focused on selecting projects in remote communities where electricity is generated from relatively expensive diesel fuel, and in locations where power purchase rates are higher or where the project economics appear reasonably attractive even with the low rates offered by Canadian utilities. Limited investment incentives have been offered through a three-year, accelerated depreciation schedule for small hydro equipment. Recently, renewable energy industry members have begun to band together to present their views on the power purchase and tax policy issues to federal and provincial governments.

The next step in this process would logically be for the interested parties to increase the dialogue on this issue. In this approach, the role of the federal government would be to facilitate interaction among industry groups, provincial agencies and utilities. The key policy levers would rest with the provincial governments, and the difficulties which utilities have in offering reasonable power purchase rates could be discussed in a public forum.

REFERENCES:

- Acres International Ltd., Hydrologic Design Methodologies for Small Scale Hydro at Ungauged sites Phase II, Report, April, 1985, for Environment Canada and Energy, Mines and Resources Canada.

- Bateman, L.A., L. Ingram, G.C. Baker, W.R. Jenkner, The Challenge of Economic Development of Canada's Low-head Hydro Potential, World Energy Conference, 1983.

- B.C. EMPR, Ministry of Energy, Mines and Petroleum Resources, Small Hydro Power Resources in the Provincial System, Sigma Engineering Ltd., 1984.

- B.C. Hydro, Alternative Energy Resources for Electric Power Generation, Report, July 1983.

- Clark, R.H., Review and Assessment of Hydraulic Energy Research and Development Program, EMR Report, November, 1985.

- Crippen Consultants Ltd., Micro Hydro Vol. I: A Survey of Potential Micro Hydro Developments for Use by Remote Communities in British Columbia, EMR Report ER80-9E, 1980.

- Crumplin, W., University of Western Ontario, Assessment of Development of Small Hydroelectric Energy in Eastern Canada, Report for EMR, January, 1986.

- Daborn, G.R., Environment Implications of the Fundy Bay Tidal Power Development, Water Power and Dam Construction, April, 1985.

- Davis, Barry V., and D.H. Swan, Nova Energy Ltd., Nova Scotia, Vertical Axis Turbine Economic for Rivers and Estuaries, Modern Power Systems, Feb. 1983, p.29-34.

- EMR, Energy, Mines and Resources Canada, Water Power Resources Inventory, 1964.

- EMR, Energy, Mines and Resources Canada, Roddickton Mini-Hydro Development: A Guide to Design and Construction, Report, 1983.

- EMR, Energy, Mines and Resources Canada, Electric Power In Canada -- 1984, Annual Report.

- EMR, Energy, Mines and Resources Canada, New Conservation Initiatives Announced by Energy Minister, Communique, May, 1985.

- EMR, Energy, Mines and Resources Canada, Federal Energy R&D Focuses on Economic Renewal, Communique, July, 1985.

- Faure, T.D., Experimental Results of a Darrieus Type Vertical Axis Rotor, In A Water Current, National Research Council Canada, Report TR-HY-000, 1984.

- Highquest Engineering Inc., Ultra-Low Head Tidal Power: Technology and Site Assessment, March, 1985 for National Research Council Canada.

- Hydro Quebec, Potentiel Hydraulique Non Aménagé Des Petites Centrales, Report, 1980.

- Judge, D., et al, Hydrologic Design Methodoloies for Prefeasibility of Small Hydro at Ungauged Sites, Canadian Society for Civil Engineering Annual Conference, May, 1985.

- Monenco Ltd., Identification of Environmentally Compatible Small Scale Hydroelectric Potential in Atlantic Canada, for EMR and Environment Canada, January, 1984.

- Moore, L., Small Hydro: A View from Above, Hydro Review, Spring 1984, p.37.

- Moore, L, Small Hydro: A View of the Canadian Scene, Annual National Conference of the Solar Energy Society of Canada, August 2-6, 1984.

- Ontario Hydro, Developed Water Power Resources Other Than Ontario Hydro, Report No. 213-201, 1976-1979.

- Ontario Hydro, Hydraulic Power Resources of the Province of Ontario, Inventory Report No. 82572, December, 1982.

- Ontario MNR, Ministry of Natural Resources, List of Water Powers In Ontario, 1983.

- Passmore Associates International, U.S. Utility Attitudes and Experiences with the Public Utility Regulatory Policies Act (PURPA) and its Potential Relevance in Canada, for EMR Report, March, 1985.

- Shawmont Newfoundland Ltd., Study of Small Scale Hydro for Newfoundland and Labrador Report I&II, 1979 for Newfoundland & Labrador Hydro.

- Sigma Engineering Ltd., Energy Overview Study for Remote Communities in British Columbia, 1983, For Energy, Mines and Resources Canada.

- Simons (International) Ltd., et al An Ultra-Low Head Approach to Tidal Energy, March, 1984, for National Research Council Canada.

- Statistics Canada, Electric Power Statistics, Volume III, Dec., 1983.

. Tidal Power Corporation, Nova Scotia, Fundy Tidal Power Update'82.

. Tung, T.P., J.C. Barclay, Small Scale Hydro Development in Canada -- An Overview of Federal Activities and Policy, Water power '85, September 24-27, 1985.

T. P. Tung is Technology Coordinator - Hydraulic Energy, Renewable Energy Division, Energy, Mines and Resources Canada.

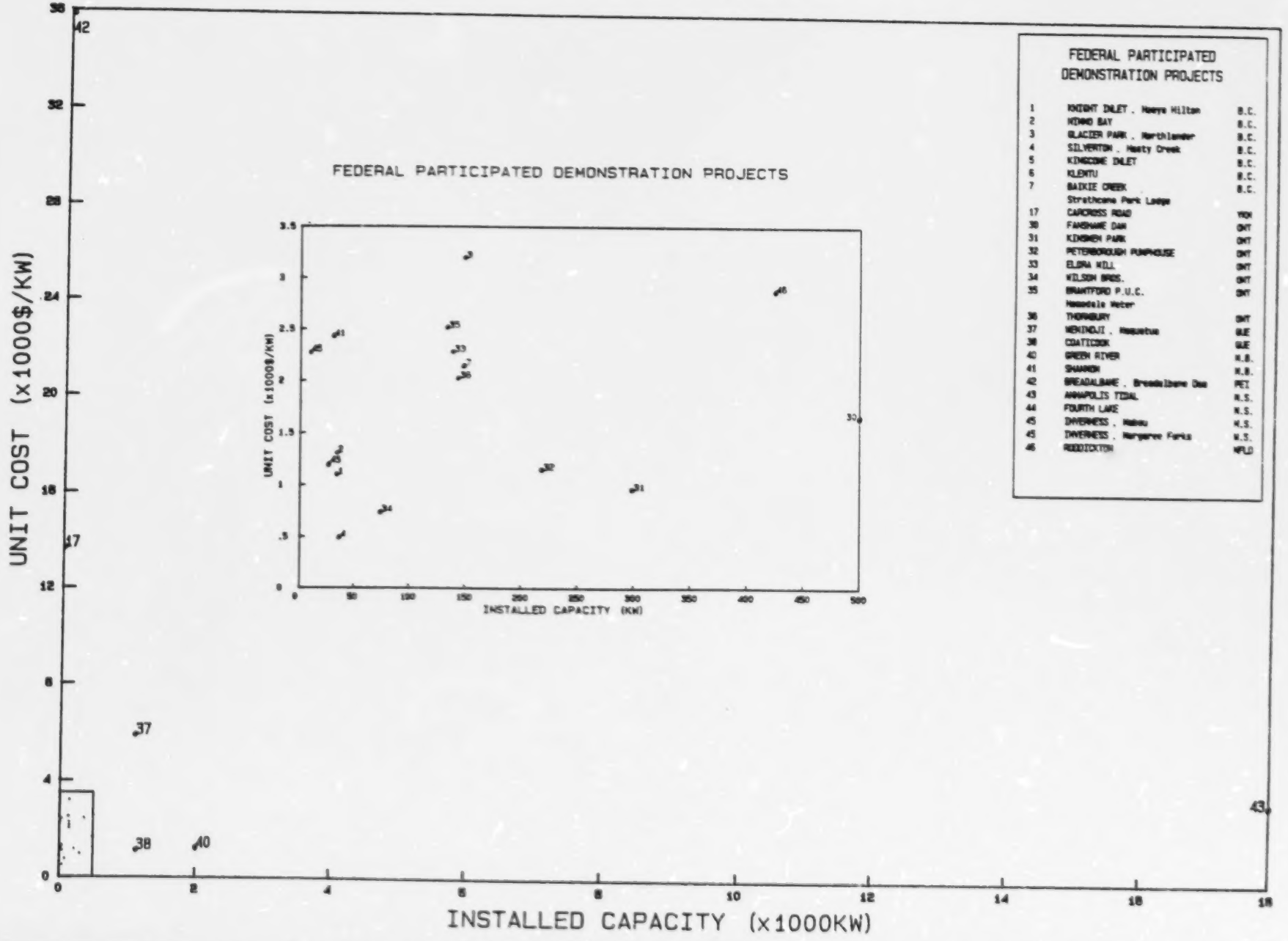
J. C. Barclay is Senior Policy Analyst, Renewable Energy Division, Department of Energy, Mines and Resources Canada.

FEDERAL PARTICIPATED DEMONSTRATION PROJECTS

SITE NAME	LOCATION	OUTPUT (KW)	HEAD (M)	TYPE OF OWNER	TOTAL COST ($'000)	UNIT COST ($/KW)
Hoeya Hilton	Knight Inlet, B.C.	35	80	Remote Resort Fishing Camp	39	1,105
Nimmo Bay Resort	Nimmo Bay, B.C.	35	64	Remote Fishing Camp	46	1,314
Northlander Lodge	Glacier National Park, B.C.	150	64	Remote Tourist Lodge	330	3,200
Hasty Creek	Silverton B.C.	37.5	60.4	Private Business	19	501
Strathcona * Park Lodge	Balkie Creek B.C.	150	140	Remote Tourist Lodge	323*	2,153
Carcross Road	Whitehorse Yukon	1.6	9	Private Business	22	13,688
Fanshawe Dam	London Ontario	500	11.3	Conservation Authority	830	1,660
Kinsmen Park	Sault Ste-Marie Ontario	300	44.2	Non-Profit Organization	290	967
Peterborough Pumphouse	Peterborough Ontario	220	3	Public Utilities	255	1,159
Elora Mill	Elora Ontario	140	10.3	Private Tourist Mill	320	2,286
Wilson Bros. Mill	Fergus Ontario	75	4.6	Private Flour Mill	56	747
Homedale Water Plant	Brantford Ontario	135	3.6	Public Utilities	340	2,519
Thornbury Dam	Thornbury Ontario	145	6.7	Private Tourist Mill	295	2,034
Maquatua	Wemindji Quebec	1,100	10	Remote Community	6,500	5,909
Coaticook*	Coaticook Quebec	1,120	9	Municipality	1,300*	1,161
Green River	Edmunston N.B.	2,000	6.1	Municipality	2,501	1,251
McCrea Farms	Shannon N.B.	31	13.6	Private Farm	75	2,432
Breadalbane Dam	Breadalbane PEI	3.5	3	Remote Community	126	35,914
Annapolis Tidal	Annapolis Royal Nova Scotia	18,000	5.5	Tidal Power Corporation	60,000	3,333
Mabou	Inverness Nova Scotia	10	30.5	Residential	23	2,280
Margaree Forks	Inverness Nova Scotia	28	5.2	Residential	34	1,214
Roddickton	Roddickton Newfoundland	425	42	Remote Community	1,225	2,882

* Projects Under Construction

FEDERAL PARTICIPATED DEMONSTRATION PROJECTS



FEDERAL PARTICIPATED DEMONSTRATION PROJECTS

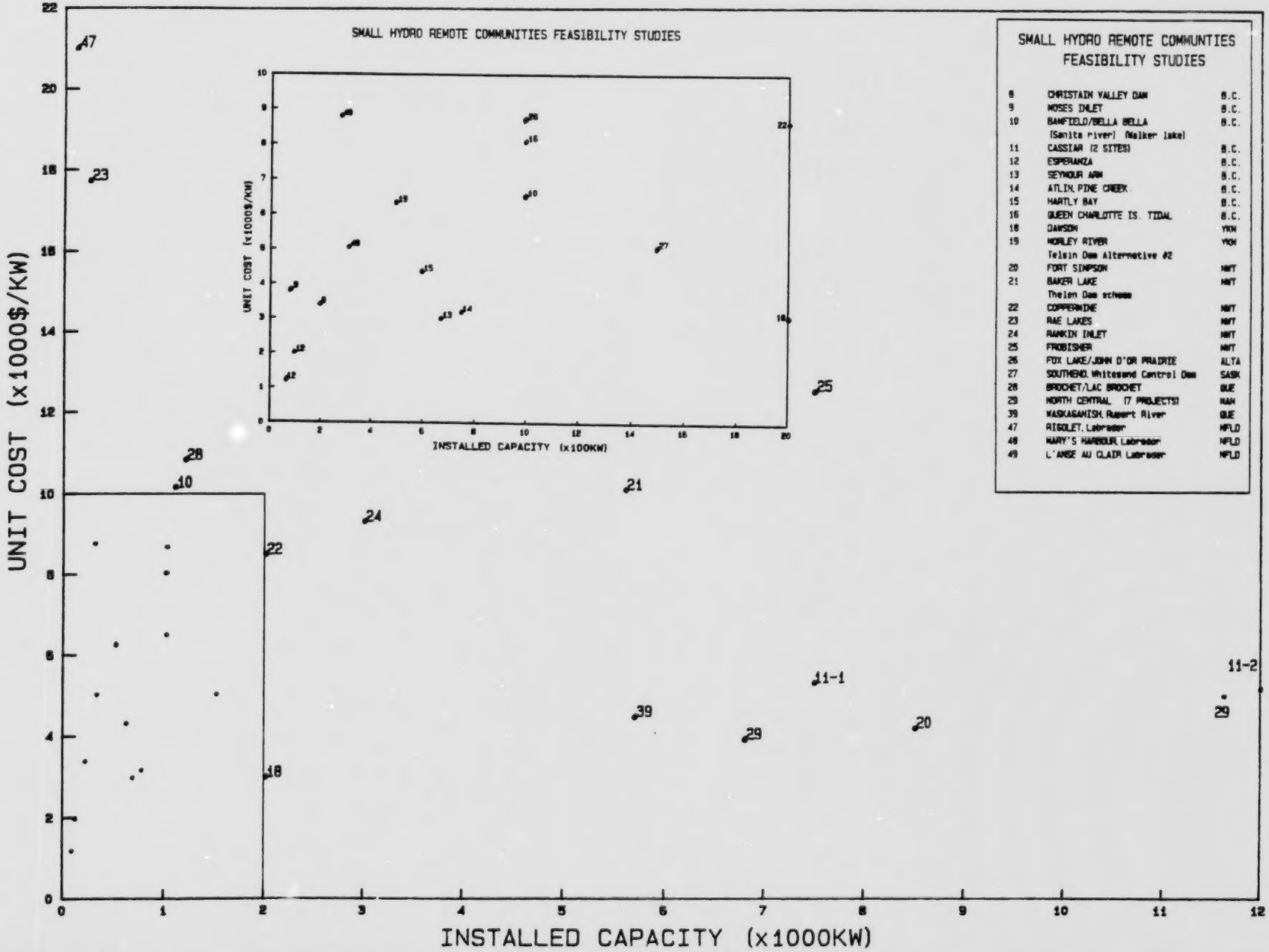
FEDERAL PARTICIPATED DEMONSTRATION PROJECTS

1	KNIGHT INLET , Meare Hilton	B.C.
2	KEMANO BAY	B.C.
3	GLACIER PARK , Northlander	B.C.
4	SILVERTON , Hasty Creek	B.C.
5	KINGCOME INLET	B.C.
6	KLEMTU	B.C.
7	BAIKIE CREEK	B.C.
	Strathcona Park Lodge	
17	CARCROSS ROAD	YUK
30	FANSHAWE DAM	ONT
31	KINSMEN PARK	ONT
32	PETERBOROUGH PUMPHOUSE	ONT
33	ELORA MILL	ONT
34	WILSON BROS.	ONT
35	BRANTFORD P.U.C.	ONT
	Hagersville Water	
36	THORNBURY	ONT
37	MENINDJI , Wagwetua	QUE
38	COATICOOK	QUE
40	GREEN RIVER	N.B.
41	SHANNON	N.B.
42	BREADALBANE , Breadalbane Dam	PEI
43	ANNAPOLIS TIDAL	N.S.
44	FOURTH LAKE	N.S.
45	INVERNESS , Mabou	N.S.
45	INVERNESS , Margaree Forks	N.S.
46	REDDITCH	NFLD

SMALL HYDRO REMOTE COMMUNITIES FEASIBILITY STUDIES

Site Name & Location	Potential Output (kW)	Head (M)	Cost Estimate ($1,000)	$/kW
Christian Valley Dam, Westbridge, B.C.	200	457	676	3,380
Moses Anlet Camp, Moses Inlet, B.C.	90	105	312	3,818
Sarita River, Bamfield, B.C.	1,000	43	6,505	6,505
Walker Lake, Bella Bella, B.C.	1,100	75	11,171	10,155
Cassiar, B.C.	7,500/ 12,000	167/ 186	39,900/ 61,500	5,320/ 5,125
Cover Creek, Esperanza, B.C.	65	85.4	77.6	1,195
Lutes Creek, Esperanza, B.C.	100	55.5	198	1,980
Seymour Arm, Seymour Arm, B.C.	675	88	2,018	2,989
Pine Creek, Atlin, B.C.	750	68	2,387	3,180
Hawkesbury Island, Hartley Bay, B.C.	600	-	2,600	4,333
Juskatla Narrows, Queen Charlotte Islands, B.C.	1,000	N/A	8,060	8,060
Klondike North Fork, Dawson, Yukon	2,000	65	6,000	3,000
Morley River Hydro, Teslin, Yukon	500	38	3,155	6,310
Fort Simpson, Trout Lake, N.W.T.	8,500/ 5,500	26.6/ 27.9	58,823	4,202
Thelon Dam Scheme, Baken Lake, N.W.T.	5,600	8.4	56,580	10,103
Bloody Falls, Coppermine, N.W.T.	2,000	5.06	16,000	8,510
Rae Lakes, N.W.T.	250	5.4	4,439	17,756
Rankin Inlet, N.W.T.	3,000	13.7	25,156	9,317
Frobisher, N.W.T.	7,500	46.75	93,981	12,531
Vermilion Falls, Fox Lake/John D'Or Prairie, Alberta	1,000	4.5	8,693	8,693
Whitesand Control Dam, Southend, Saskatchewan	1,500	6.8	7,560	5,040
Cochrane River, Brochet/Lac Brochet, Manitoba	1,200	5	13,000	10,833
North Central Manitoba (7 projects)	6,800- 11,600	6.0- 10.0	31,450- 46,260	3,919- 4,992
Rupert River, Waskaganish, Quebec	5,700	6.5	25,500	4,474
Rigolet, Newfoundland	125	34.4	2,630	21,040
Mary's Harbour, Mary's Harbour, Newfoundland	280	9.9	2,454	8,764
L'Anse au Clair, Newfoundland	314	66.4	1,580	5,031

SMALL HYDRO REMOTE COMMUNITIES FEASIBILITY STUDIES


SMALL HYDRO REMOTE COMMUNITIES FEASIBILITY STUDIES
UNIT COST (x1000$/KW)
INSTALLED CAPACITY (x1000KW)
UNIT COST (x1000$/KW)
INSTALLED CAPACITY (x100KW)
SMALL HYDRO REMOTE COMMUNITIES FEASIBILITY STUDIES
6 CHRISTAIN VALLEY DAM B.C.
9 MOSES INLET B.C.
10 BANFIELD/BELLA BELLA B.C.
(Sanita river) (Walker lake)
11 CASSIAR (2 SITES) B.C.
12 ESPERANZA B.C.
13 SEYMOUR ARM B.C.
14 ATLIN, PINE CREEK B.C.
15 HARTLY BAY B.C.
16 QUEEN CHARLOTTE IS. TIDAL B.C.
18 DAWSON YKN
19 MORLEY RIVER YKN
Telsin Dam Alternative #2
20 FORT SIMPSON NWT
21 BAKER LAKE NWT
Thelon Dam scheme
22 COPPERMINE NWT
23 RAE LAKES NWT
24 RANKIN INLET NWT
25 FROBISHER NWT
26 FOX LAKE/JOHN D'OR PRAIRIE ALTA
27 SOUTHEND, Whitesand Control Dam SASK
28 BROCHET/LAC BROCHET QUE
29 NORTH CENTRAL (7 PROJECTS) MAN
39 WASKAGANISH, Rupert River QUE
47 RIGOLET, Labrador NFLD
48 HARY'S HARBOUR, Labrador NFLD
49 L'ANSE AU CLAIR Labrador NFLD

SMALL SCALE AND LOW HEAD HYDRO DEMONSTRATION PROJECTS

SMALL HYDRO DEVELOPMENT ON ONTARIO'S HERITAGE CANALS

James C. Christakos
Director, Ontario Region
Parks Canada

The purpose of this paper is to describe Parks Canada's policy with respect to proposals for small hydro generation on Ontario's Heritage Canals and to identify the requirements to be met by the proponents of such proposals. The canals to be discussed are the Rideau Canal and the Trent-Severn Waterway.

Before describing the policy, it is important to appreciate the nature of the canals and Parks Canada's canal objectives.

The Rideau Canal and the Trent-Severn Waterway, linked by the Bay of Quinte and the scenic bays and reaches of Prince Edward County, form a 680-kilometre navigable waterway, which is one of Canada's most treasured heritage and recreational resources. Stretching from Ottawa to Georgian Bay, the canal corridor is shaped like a giant horseshoe cutting across the heart of Ontario's recreation land astride the major Toronto-Montreal transportation axis. The waters of this corridor compose one of North America's most beautiful and varied inland pleasure craft routes. The corridor is a mélange of historical, recreational and natural features, forming a magnificent system of beaches, fishing waters, wildlife areas, outstanding scenic landscapes, nationally significant heritage resources and rapidly developing urban tourist service centres. Moreover, it is within a day's drive of over 60 million people and attracts more boaters and fishermen than any other part of Ontario. The economic importance to Ontario and Canada of this internationally recognized resource is substantial, producing in excess of 1.2 billion tourism dollars annually.

The Rideau Canal was built between 1826 and 1832. Today, it is recognized as one of the best preserved 19th century canals still in active operation in the world, and is an operating memorial to the dedication, perseverance and ingenuity of its creator, Lt. Colonel John By.

At about the same time navigation began on the Rideau, work was started on the first links of the Trent Canal to enable steam-driven boats and lumber rafts to traverse the Kawartha

Lakes and the Trent and Severn River connections. Through man and horse power, its construction evolved sporadically over the years to its final completion in 1920.

Both the Rideau Canal and the Trent-Severn Waterway have been declared to be of national historic significance in recognition of their outstanding heritage resources and their unique place in Canada's history.

In 1972, administrative and operational responsibility for the canals was transferred from the Ministry of Transport to Parks Canada on the understanding that future emphasis for management of these canals would shift from transportation to recreation, and protection, enjoyment and interpretation of their natural and cultural heritage values. This new emphasis on preservation and presentation resulted in canal management responsibilities being broadened to include not only the maintenance of navigation and the control of water levels, but the preservation, interpretation and, where necessary, the restoration of historic buildings and structures, the preservation and interpretation of natural environment resources, and the achievement of optimum use of federal lands to enhance public recreational opportunities and enjoyment.

In 1975, the governments of Canada and Ontario signed the Canada-Ontario Rideau, Trent-Severn (CORTS) Agreement to co-ordinate their efforts to develop a distinctive environmental corridor along the canals. Through extensive research and public consultation, the governments produced a set of policies for the Rideau, Trent-Severn Corridor to guide public and private sector activities in the areas of pollution abatement, water management, land use, tourism and recreation, and heritage conservation. By their commitment to co-ordinated development of this corridor, the governments encourage continuing participation by municipalities and the private sector, so that a wide variety of recreational opportunities are available to users in a safe, pleasant and interesting environment.

As the federal agency responsible for the operation and management of the canals and canal lands, and as partner to the CORTS Agreement, Parks Canada's two major objectives for the canals are:

- To preserve and interpret the canals and their structures as a functioning system of national historic significance, while at the same time operating and maintaining them as recreational waterways, and making maximum recreational use of canal lands; and

- To co-ordinate federal activities with the Province of Ontario to develop a distinctive environmental corridor wherein optimum recreational use is achieved without detriment to the historical and natural setting.

These objectives are being achieved through the implementation of Parks Canada's ongoing program of works for the canals and the CORTS policies.

The use of the canals for hydroelectric power generation has a long history. Concurrent with the construction of the Trent-Severn Waterway, twenty-two power stations were built, utilizing the heads made available by dam construction and improved stream flow from the reservoir systems. Seventeen stations are still in operation. The Rideau Canal experienced similar development, though to a lesser extent. Today, there are six stations operating on the Rideau. There are also approximately fifty undeveloped sites on the canals which appear to offer potential for small hydro development (under 2 megawatts).

Parks Canada recognizes that small hydro is a fast-growing, multi-million dollar industry in Ontario, and supports the federal and provincial policy to encourage such developments as an economical and environmentally attractive source of indigenous and renewable energy. The province offers small hydro assistance programs and Ontario Hydro has a new rate structure which encourages the development of independent small hydro facilities. A positive climate exists for small hydro development and Ontario is a world leader in the industry.

The Heritage Canals offer considerable potential for small hydro development and there are growing demands in the marketplace to make greater use of the canals for this purpose. In order to accommodate these demands and at the same time protect the canals' heritage values and respect existing water management priorities, Parks Canada has produced a policy to guide small hydro development on the Rideau, Trent-Severn system.

The policy facilitates small hydro development, where appropriate on the canals, by identifying the requirements to be met by the proponents of such developments. The proponents may be private enterpreneurs, municipalities, public utility commissions or conservation authorities.

In preparing the policy, Parks Canada was guided by the CORTS policies on water control in which Canada and Ontario agreed that hydro generation would be dependent upon the availability of water surplus to canal operational needs, and would be weighed against other important demands. The governments further agreed that hydro proposals would be considered for approval if they are of public benefit, have acceptable environmental effects and do not conflict with other essential or higher-priority water uses. Parks Canada's policy on small hydro development reflects this direction.

While recognizing the importance of hydro generation on the canals, our policy directs that new power plants be compatible

with the heritage environment of the area, and be viable within the limitations of Parks Canada's water management priorities. These priorities include: the maintenance of navigation; the supply of water for municipal, domestic, industrial and agricultural use, flood abatement, the maintenance of water quality; the protection of aquatic habitat; the provision of opportunities for water-based recreation, and the supply of water to existing hydro facilities. Parks Canada will approve only those new hydro proposals which do not conflict with the canals' heritage values and use water that is surplus to these priority uses.

The requirements identified in the policy are intended to assist proponents in developing their small hydro proposals. Major features of the policy which describe the requirements to be met by proponents and what they can expect from Parks Canada include:

Proponents will be required to:

- Pay all costs associated with the planning, development and operation of the power plant;
- Prepare a feasibility study to determine the economic viability of the proposal;
- Obtain public reaction to the proposal through a consultation program satisfactory to Parks Canada;
- Only use water which is surplus to the priority needs of the canals and operate the plant within flow ranges prescribed by Parks Canada;
- Design the plant to be compatible with Parks Canada's operations and the historical, natural and aesthetic qualities of the site, and maintain it in good and safe condition;
- Ensure that Parks Canada's activities in managing water levels and flows are not adversely affected by the establishment of the power plant;
- Submit detailed plans and drawings of the project for Parks Canada's approval; and
- Enter into a water power agreement with Parks Canada which provides for a return to the Crown for the value of the power generated based on the rates and factors for such rights current in the industry;

Parks Canada will:

- Supply the proponent with information on relevant planning and operational matters;

- Review and input data to the proposal as required;

- Evaluate the proposal in relation to management planning concerns and the operational requirements specified in the policy; and

- Whenever appropriate, issue a licence to the proponent for the use of canal lands and water.

The foregoing discussion highlights the main thrusts of the policy and does not represent a complete list of the policy's requirements. A copy of the "Low-Head Power Generation Policy on Heritage Canals" is appended to this paper.

Parks Canada will consider all small hydro proposals on the canals and will either approve or reject them on the basis of how well they satisfy the requirements of the policy. Each water power agreement will be negotiated between the proponent and Parks Canada, and plant operation will be monitored to ensure compliance to the terms of the agreement.

The policy will enable Parks Canada to respond in a timely manner to demands for small hydro development on the canals, and will ensure that the values and uses of the canals are respected for the benefit of all users. At the same time, it will hopefully provide proponents with sufficient information to determine their interest in developing small hydro power on Ontario's Heritage Canals.

James C. Christakos is Director of the Ontario Region of Parks Canada, a position he has held since 1975.

A native of Prince Albert, Saskatchewan, Mr. Christakos has been with Parks Canada since 1960.

PARKS CANADA

MANAGEMENT DIRECTIVE 5.1.9

LOW-HEAD POWER GENERATION ON HERITAGE CANALS

APRIL 1985

FILE: C8610-0
C1425-102-21

CONTACT: PLANNING DIVISION
ONTARIO REGION

PURPOSE

To define Parks Canada's policy with respect to proposals for low-head power generation on Heritage Canals in Ontario and to identify the requirements to be met by the proponents of such proposals.

REFERENCES AND RELATED AUTHORITIES

Parks Canada Policy, p. 50, Sections 2,3
Dominion Water Power Regulations

Navigable Waters Protection Act

Federal Environmental Assessment and Review Process
Canada-Ontario Policies for Rideau, Trent Severn Corridor, p. 16
Lakes and Rivers Improvement Act

Environmental Assessment Act
Building Code
Fisheries Act
Ontario Water Resources Act

Electrical Safety Code
Power Corporation Act

Ontario Ministry of Energy Policy to Encourage Private Development of Small Hydroelectric Sites

PARCS CANADA

DIRECTIVE ADMINISTRATIVE 5.1.9

LES CENTRALES DE BASSE CHUTE SUR LES CANAUX HISTORIQUES

AVRIL 1985

DOSSIER: C8610-0
C1425-102-21

CONTACT: DIVISION DE LA PLANIFICATION
RÉGION DE L'ONTARIO

BUT

Définir la politique de Parcs Canada au sujet des projets de centrales de basse chute sur les canaux historiques et déterminer les exigences auxquelles devront répondre les promoteurs de ces projets.

RÉFÉRENCES ET AUTORISATIONS CONNEXES

Politique de Parcs Canada, p. 50, Sections 2, 3
Règlement sur les forces hydrauliques du Canada
Loi sur la protection des eaux navigables
Processus fédéral d'évaluation et d'examen en matière d'environnement

Loi sur l'aménagement des lacs et des rivières
Loi sur l'évaluation de l'environnement
Code du Bâtiment
Loi sur les pêcheries
Loi sur les ressources en eau de l'Ontario

Code sur la sûreté de l'électricité
Loi sur la Société provinciale de l'électricité
Ontario Ministry of Energy Policy to Encourage Private Development of Small Hydroelectric Sites (publié en anglais seulement)

DEFINITIONS

Low-head power generation: The generation of hydroelectric power at sites with capacities of less than 2 megawatts. Potential sites for low-head power generation in Ontario have been identified by the Ontario Ministry of Natural Resources.

"Surplus" water: Water which is in excess of the amount required to meet the needs of canal operations and navigation, environmental protection, municipal and domestic water use, and existing commitments to power companies and industrial users.

"Surging": The practice of passing a large volume of water through a plant in a short period of time then returning to the regular rate.

"Management plan": An overall development and use plan prepared by Parks Canada in consultation with the public and other interests for a site or area on a canal.

BACKGROUND

The Ontario Ministry of Natural Resources has developed a list of sites within the province which have potential for low-head power generation. Parks Canada owns and operates number of dams which are included on this list.

Recent advancements in low-head power technology, coupled with increasing costs for non-renewable energy, have made previously marginal power sites more viable. Hence, Parks Canada could receive an increased number of proposals to generate low-head power from hydro-

DÉFINITIONS

La production d'énergie par des centrales de basse chute: La production d'énergie hydro-électrique aux sites avec une capacité inférieure à 2 megawatts. Les sites possibles de centrales de basse chute en Ontario ont été identifiés par le ministère des Ressources naturelles de l'Ontario.

L'eau "en surplus": L'eau qui est en excès de la quantité nécessaire pour répondre aux besoins du fonctionnement des canaux, de la navigation, des exigences municipales, des demandes domestiques, de la qualité de l'environnement et des ententes existantes avec les compagnies hydro-électriques et les industries.

La surpression: La technique qui consiste à faire passer dans une centrale, pendant une courte période de temps, une plus grande quantité d'eau et à retourner ensuite au débit normal.

"Plan de gestion": Un plan global d'aménagement et d'utilisation d'un site ou d'un secteur adjacent à un canal, élaboré par Parcs Canada en consultation avec le public et les groupes d'intérêt concernés.

ÉTAT DE LA QUESTION

Le ministère des Ressources naturelles de l'Ontario a établi une liste des sites où pourraient être construites des centrales de basse chute. Parcs Canada possède et administre un grand nombre des barrages figurant sur la liste en question.

Les derniers progrès en matière de production d'électricité par centrale de basse chute, ainsi que l'augmentation des coûts de l'énergie non renouvelable, rendent plus intéressants ces sites considérés auparavant comme secondaires. Par conséquent Parcs Canada pourrait recevoir, de la part des

electric authorities, private developers and municipalities. This policy is intended to deal effectively with proposals to generate low-head power at sites along Parks Canada's Heritage Canals in Ontario.

responsables de l'hydro, des promoteurs privés et des municipalités, un plus grand nombre de propositions concernant la production d'électricité par centrale de basse chute. La présente politique indique comment répondre aux propositions visant à construire des centrales de basse chute le long des canaux historiques de Parcs Canada en Ontario.

DIRECTIVES

This policy on low-head power generation is based on Parks Canada's water management priorities for Heritage Canals and on the Memorandum of Agreement between the Department of Indian and Northern Affairs and Parks Canada regarding administrative authority for the Dominion Water Power Regulations on Heritage Canals. Water management priorities include the maintenance of navigation; the supply of water for municipal, domestic, industrial and agricultural purposes; the abatement of flooding; the protection of environmental quality and wildlife habitat; the provision of opportunities for water-based recreation; and the fulfillment of existing power agreements. New power plants would have use of water which is surplus to these priorities. This policy is also based on the experience and operational constraints associated with existing power plants on Heritage Canals.

DIRECTIVES

La présente politique se fonde sur les priorités établies par Parcs Canada en matière de gestion des eaux, pour les canaux historiques et sur le protocole d'entente conclu entre le ministère des Affaires indiennes et du nord et Parcs Canada au sujet de l'administration du Règlement sur les forces hydrauliques du Canada, relativement aux canaux historiques. Les priorités de Parcs Canada en gestion des eaux sont les suivantes: maintenir les activités de navigation, préserver la qualité de l'environnement et protéger les habitats fauniques; réduire les inondations; faciliter la pratique des sports nautiques; assurer l'approvisionnement en eau des municipalités, des entreprises et des exploitations agricoles; et réaliser les ententes existantes de fourniture d'énergie électrique. Les nouvelles centrales pourraient utiliser l'eau excédentaire non requise pour la satisfaction de ces besoins prioritaires. La politique se fonde aussi sur l'expérience acquise avec les centrales déjà construites sur les canaux historiques et sur les contraintes opérationnelles occasionnées par ces centrales.

Heritage Canals are navigation routes which include a variety of cultural, natural and recreational resources. It is Parks Canada's objective to protect heritage resources along these canals and to operate them for recreational use. Navigation along these canals will be maintained as an inherent part

Les canaux historiques sont des voies de navigation qui, en plus de constituer une richesse naturelle, offrent toutes sortes de possibilités sur le plan culturel et des loisirs de plein air. Parcs Canada s'est fixé comme objectif de protéger les ressources du patrimoine le long de ces canaux et de les exploiter à des fins récréatives. La

of their heritage value and water use precedent thereto takes priority.

Hydroelectric power generation has a long history along the Heritage Canals and will continue to be an important activity in the future.

Parks Canada will consider all proposals to generate low-head power on Heritage Canals and while Parks Canada has the authority to approve or not approve any development proposals, each individual agreement will be negotiated between the proponent and Parks Canada. A list of conditions which Parks will, where necessary, require that a proponent meet is attached as Appendix A to this policy.

navigation y sera maintenue comme une valeur intégrante du patrimoine, mais c'est l'utilisation de l'eau qui a priorité.

La production d'hydroélectricité est intimement liée à l'histoire des canaux de notre patrimoine et l'importance de cette activité sera maintenue au cours des années à venir.

Parcs Canada considérera toutes les propositions de produire de l'électricité au moyen de centrales de basse chute sur les canaux historiques et, même s'il a le pouvoir de les approuver ou de les rejeter, chaque entente individuelle sera négociée avec le promoteur. Parcs Canada peut exiger du promoteur qu'il remplisse certaines conditions (voir liste à l'Annexe A de la présente).

Assistant Deputy Minister
(Parks Canada)

Sous-ministre adjoint
(Parcs Canada)

A.T. Davidson

APPENDIX A

1. All costs associated with a power plant, including those necessary to meet Parks Canada's requirements and to obtain other necessary approvals, will be the responsibility of the proponent/operator. This includes the costs of providing data required by Parks Canada as well as any additional operation and maintenance costs to Parks Canada associated with developing or operating the power plant and satisfying the requirements of the Dominion Water Power Regulations and the Federal Environmental Assessment and Review Process (EARP). If Parks Canada is required to perform any work resulting from the presence of the plant, the operator will reimburse Parks Canada for such expenditures.

2. Any agreement between Parks Canada and the proponent for generating power on Parks Canada's Heritage Canals shall comply with the Dominion Water Power Regulations. These Regulations provide for a return to the Crown for the value of generating power based on the rates and factors for such rights current in the industry.

3. In any periods of short water supply, canal operational requirements, water quality objectives and domestic needs will take precedence over power generation. Therefore, the quantity of water available for power generation will be determined by Parks Canada and will only be that which is surplus to priority needs. For river locations, a water level "range" will be set by Parks Canada for each site. For lake sites, plant flow will be

ANNEXE A

1. Tous les coûts reliés à la construction de la centrale, y compris les frais engagés pour satisfaire aux exigences de Parcs Canada ou pour obtenir les autres approbations nécessaires, sont à la charge du promoteur/exploitant. Cela comprend les coûts engagés pour la fourniture des données exigées par Parcs Canada, ainsi que tous frais de fonctionnement et d'entretien supplémentaires encourus par Parcs Canada suite à l'aménagement ou l'exploitation de la centrale et à l'application des exigences du Règlement sur les forces hydrauliques du Canada et du Processus fédéral d'évaluation et d'examen en matière d'environnement (PEEE). Si Parcs Canada doit exécuter des travaux, quels qu'ils soient, attribuables à l'existence de la centrale sur le canal, l'exploitant doit le rembourser des dépenses engagées à cette fin.

2. Toute entente conclue entre Parcs Canada et le promoteur pour la production d'électricité sur les canaux historiques de Parcs Canada devra se conformer au Règlement sur les forces hydrauliques du Canada. Le Règlement prévoit notamment, une rétribution à la Couronne pour la valeur de l'électricité produite, calculée d'après les taux et les facteurs appliqués dans l'industrie pour ces droits.

3. En cas de pénurie d'eau, le fonctionnement des canaux, les besoins locaux et les objectifs relatifs à la qualité de l'eau auront préséance sur la production d'électricité. En conséquence, la quantité d'eau pouvant servir à la production d'électricité sera déterminée par Parcs Canada et représentera l'excédent de la quantité nécessaire aux besoins prioritaires. Pour les rivières, Parcs Canada établira une "fourchette" de niveau d'eau pour chaque site. Pour les lacs, le débit

set daily by Parks Canada. The operator of the power plant will provide gauging data when requested by Parks Canada and will operate the plant within the established ranges of flows.

des centrales sera fixé chaque jour par Parcs Canada. L'exploitant de la centrale devra fournir, à la demande de Parcs Canada, des mesures de débit, et faire fonctionner la centrale en respectant les limites et les débits prescrits par Parcs Canada.

4. Parks Canada will ensure that existing power plant operations are not adversely affected by future developments.

4. Parcs Canada veillera à ce que le fonctionnement des centrales existantes ne souffre pas des projets ultérieurs.

5. The development and operation of a power plant must be compatible with Parks Canada's site operations and access, and must not preclude other public land uses. The design of the plant must be satisfactory to Parks Canada with the building and associated power lines being designed and located so as not to unreasonably detract from the historical, natural and aesthetic character of the site and, wherever practical, screened from view. The plant must be safe for the public to approach, with safety devices being harmoniously designed and installed. The operator is expected to maintain the site, plant and equipment in good repair.

5. L'aménagement et l'exploitation d'une centrale ne doit pas nuire aux activités de Parcs Canada et à l'accès au lieu, ni empêcher toute autre utilisation des terres par le public. La conception de la centrale doit être à l'entière satisfaction de Parcs Canada, avec un bâtiment et des lignes de transport électrique compatibles avec le caractère historique, naturel et esthétique du lieu et, lorsque c'est possible, dissimulés au regard. Parcs Canada ne permettra pas l'altération ou la destruction de l'intégrité historique ou du caractère panoramique du lieu. Le public doit pouvoir s'approcher sans danger de la centrale, dont les dispositifs de sécurité seront conçus et installés harmonieusement. L'exploitant devra maintenir le lieu, la centrale et le matériel en bon état.

6. Parks Canada's activities in managing water levels and flows must not be adversely affected by the establishment of a power plant. In this regard,

6. L'érection de la centrale ne doit pas nuire aux activités de Parcs Canada concernant la régulation des niveaux et des débits de l'eau. À cet égard,

a) The developer will be required to install lights on the power dam in the event that Parks Canada has to perform work on the dam such as adding or removing stop logs;

a) le promoteur devra installer des lumières sur le barrage au cas où les employés de Parcs Canada auraient à exécuter des travaux, comme l'introduction ou le retrait de batardeaux;

b) The developer will be required to provide a performance bond in order to ensure his financial ability to under-

b) le promoteur devra fournir une garantie de bonne exécution afin de prouver sa capacité financière d'entreprendre la construction,

take construction, operation and maintenance of the plant;

c) Flow changes due to plant shut down or routine maintenance will be immediately compensated by corresponding stop log operations or by the operation of developer-installed automatic sluice gates to divert flows around the plant. The operator will be responsible for meeting emergency situations such as a combined plant and gate failure, in a reasonable response time to be determined by Parks Canada, so as to ensure that constant flows are maintained on the system. The number and type of spillways, or capacity of sluice gates to compensate for these emergencies, will be determined by Parks Canada. The operator will be responsible for all damages including flooding damages attributable to his actions;

d) The practice of "surging" plants to meet peak demands will not be permitted as this causes additional stop logs to be placed in dams downstream thereby possibly producing minor flooding or low water conditions for other users such as boaters, municipalities, industries and other power plants;

e) For winter operations, the developer will be required to supply electricity and heaters in selected sluices to enable Parks Canada to respond to emergency flood abatement needs. This will aid winter adjustment to stop logs and ensure that Parks Canada is able to react to sudden high flow conditions. The plant will also

l'exploitation et l'entretien de la centrale;

c) les modifications du débit résultant de la fermeture de la centrale ou de l'entretien courant seront compensées immédiatement par le jeu des batardeaux ou par la mise en marche de vannes à glissières automatiques installées par le promoteur afin de détourner les eaux autour de la centrale. L'exploitant sera responsable de prendre les mesures nécessaires en cas d'urgence, comme une panne combinée de la centrale et de la vanne, dans un temps raisonnable déterminé par Parcs Canada, afin d'assurer un débit constant dans tout le canal. Le nombre et le type de déversoirs ou la capacité des vannes à glissières destinés à parer aux situations d'urgence seront déterminés par Parcs Canada. L'exploitant sera responsable de tous les dommages, y compris les dommages attribuables à ses actions, y compris les dommages causés par les inondations;

d) le recours à la surpression pour répondre aux demandes de pointe ne sera pas autorisée, puisque cette technique entraîne l'introduction de batardeaux supplémentaires aux barrages en aval, ce qui peut provoquer de légères inondations ou un faible niveau d'eau au détriment des autres utilisateurs comme les plaisanciers, les municipalités, les entreprises privées et d'autres centrales;

e) durant l'hiver, l'exploitant devra fournir de l'électricité et des éléments chauffants pour certaines des vannes afin de permettre à Parcs Canada de réagir rapidement lors d'une inondation. La conception des éléments chauffants devra être approuvée par Parcs Canada. Cette mesure permettra d'ajuster les batardeaux aux conditions hivernales et garantira que Parcs Canada est en

be equipped with either heated automatic sluice gates to accommodate plant flows due to plant shutdown as a result of icing, or have a local work force able to respond immediately to such a plant failure by performing the necessary stop log adjustments. In the event of certain ice conditions, Parks Canada will reserve the right to have the plant cease operation until the problem is resolved; and

mesure de réagir aux crues soudaines. Afin de répondre aux accroissements de débit résultant de la fermeture de la centrale par suite du gel des eaux, il faudra soit munir la centrale de vannes à glissières chauffées automatiques, soit établir une équipe de travail locale capable de répondre immédiatement à une telle défaillance en effectuant l'ajustement nécessaire des batardeaux. Parcs Canada se réserve le droit d'ordonner la fermeture de la centrale selon les conditions de la glace jusqu'à ce que le problème soit réglé; et

f) Parks Canada may lower the reach levels at any time to carry out inspections, repairs, or reconstruction of structures. Parks Canada shall endeavour to give the operator as much advance notice as possible before carrying out this type of work. The operator would not be compensated under these circumstances.

f) Parcs Canada se réserve le droit d'abaisser en tout temps le niveau d'un bief pour faire des inspections ou des réparations, ou pour reconstruire les ouvrages en place. Parcs Canada s'efforcera d'informer l'exploitant le plus tôt possible avant d'entreprendre ce type de travaux. Dans de tels cas, l'exploitant ne sera pas indemnisé.

7. The developer will be required to carry out a public consultation program, satisfactory to Parks Canada, to obtain public reaction to the proposal.

7. Le promoteur devra mener un programme de consultation du public, répondant aux exigences de Parcs Canada, afin de connaître les réactions du public au projet.

8. The developer will be required to submit detailed drawings of the site for Parks Canada's approval. Permission to proceed with construction will be granted through a written agreement. Parks Canada will monitor all aspects of the work to ensure compliance to the terms of the agreement.

8. Le promoteur devra soumettre les plans détaillés du site à Parcs Canada. La permission de commencer les travaux sera accordée par écrit. Parcs Canada surveillera tous les aspects des travaux afin de s'assurer que les termes de l'entente sont respectés.

9. In evaluating an application for low-head power generation, Parks Canada will:

9. Dans l'évaluation d'une demande de construction de centrale de basse chute, Parcs Canada:

a) evaluate the site in relation to Parks Canada's

a) évaluera le site en fonction des plans de gestion de Parcs Canada et

management plans and the operational requirements outlined in this policy;

b) provide the applicant with information on relevant planning activities and operational constraints. Final approval to proceed will be contingent upon the developer, at the design stage, satisfying Parks Canada's operational and policy requirements including the E.A.R.P. process;

c) follow the steps and conditions required for plant approval as stated in the Dominion Water Power Regulations (see Appendix B);

d) require the preparation of a feasibility study by the developer. The feasibility study will determine the economic viability of the site;

e) review and input data to the proposal as it is being developed; and

f) ensure that a license is issued to the developer for the use of Parks Canada property and water.

des exigences opérationnelles énoncées aux présents;

b) communiquera au demandeur les informations concernant les activités de planification et les contraintes opérationnelles pertinentes. L'approbation finale d'entreprendre les travaux sera accordée si à l'étape de la conception, le promoteur répond aux exigences opérationnelles et aux exigences de la politique de Parcs Canada, ce qui comprend le Processus fédéral d'évaluation et d'examen en matière d'environnement;

c) suivra les étapes et les conditions exigées pour l'approbation d'une centrale telles qu'énoncées dans le Règlement sur les forces hydrauliques du Canada (voir Annexe B);

d) exigera que le promoteur fasse une étude de faisabilité visant à déterminer la viabilité économique du site choisi;

e) évaluera le projet tout au long de sa réalisation et communiquera les données pertinentes au promoteur; et

f) s'assurera qu'un permis est délivré au promoteur pour l'utilisation de la propriété et des eaux de Parcs Canada.

APPENDIX B

Application

3. (1) An application for a licence to divert, use or store water for power purposes may be made to the Director and shall contain the following information:

(*a*) the name, address and occupation of the applicant;

(*b*) the name or a clear description of the river, lake or other watercourse from which the water is to be diverted or used;

(*c*) the place where the water is to be diverted from or in the said watercourse, referred if possible to an established monument of the existing system of land surveys, and the place where the water is to be returned or released;

(*d*) the maximum quantity of water, expressed in cubic feet per second, which it is estimated will be ultimately diverted or used under the licence applied for;

(*e*) the estimated average head in feet which will be available for the production of power according to the plan of development proposed;

(*f*) the estimated minimum amount of energy expressed in horsepower that will be developed on the turbine shaft within five years from the date of the application or within such other period as the applicant may state to be required for the completion of his initial development;

(*g*) the maximum amount of energy expressed in horsepower which it is estimated will ultimately be developed on the turbine shaft from the waters for which application is made;

(*h*) a brief statement with respect to the character and extent of all principal works the applicant proposes to construct;

(*i*) in respect of each dam involved, its approximate maximum length and height, its proposed type and the material to be used in its construction;

(*j*) where storage is involved, the location of each lake, basin or other place in which the applicant wishes to store water;

(*k*) for each storage reservoir, the approximate number of acres of land the applicant proposes to flood, the approximate area in acres of the surface of the reservoir when filled, the estimated vertical storage range in feet, and the total capacity of storage contemplated in acre-feet; and

(*l*) a reasonably accurate description and the acreage of the lands required for occupation or use in the construction, maintenance or operation of the proposed works, noting separately lands required for rights-of-way and lands that are to be flooded

(i) within public lands,

(ii) within provincial Crown lands, and

(iii) within privately owned lands.

ANNEXE B

Demande

3. (1) Toute demande d'une concession autorisant la dérivation, l'utilisation ou l'emmagasinage de l'eau en vue de la production d'énergie peut être soumise au directeur et doit contenir les renseignements suivants:

a) le nom, l'adresse et l'emploi du demandeur;

b) le nom ou une description précise de la rivière, du lac ou autre cours d'eau dont les eaux doivent être dérivées ou utilisées;

c) l'endroit où l'eau doit être détournée de son cours ou y être amenée, avec renvoi si possible à une borne déjà établie du système d'arpentage en vigueur, de même que l'endroit par où l'eau devra être renvoyée ou relâchée;

d) la quantité maximum d'eau, exprimée en pieds cubes par seconde, éventuellement susceptible de dérivation ou d'utilisation, sous le régime de la concession demandée;

e) la hauteur estimative de chute moyenne, exprimée en pieds et disponible pour la production d'énergie d'après le plan d'aménagement proposé;

f) le minimum estimatif d'énergie, exprimé en chevaux-vapeur, susceptible de développement sur l'arbre de la turbine, dans les cinq ans qui suivront la date de la demande ou au cours de telle autre période que le demandeur déclare être requise pour parachever l'aménagement initial;

g) le maximum d'énergie, exprimé en chevaux-vapeur, et jugé devoir être susceptible de développement éventuel sur l'arbre de la turbine par les eaux qui font l'objet de la demande;

h) une description brève de la nature et de l'étendue des principaux ouvrages dont la construction est projetée;

i) en ce qui concerne chaque barrage, en indiquer la longueur et la hauteur maxima approximatives, de même que le genre de barrage projeté et les matériaux devant servir à sa construction;

j) s'il s'agit d'emmagasinage, l'emplacement de chaque lac, bassin ou autre endroit destiné à l'emmagasinage de l'eau;

k) pour chaque réservoir d'emmagasinage, le nombre approximatif d'acres de terre dont la submersion est projetée, la superficie approximative en acres de la surface du réservoir une fois rempli, la portée approximative, en pieds, du niveau du réservoir, et la capacité totale, en pieds-acre, de l'emmagasinage proposé; et

l) une description aussi exacte que possible et la superficie en acres des terrains devant être occupés ou utilisés pour fin de construction, d'entretien ou d'exploitation des ouvrages projetés, ayant soin de décrire séparément les terrains requis pour le droit de passage ainsi que ceux qui doivent être submergés

(i) dans les limites des terres publiques,

(ii) dans les limites des terres provinciales de la Couronne, et

(iii) dans les limites de propriétés privées.

(2) An application for a licence shall be accompanied by

(*a*) a preliminary plan or sketch, with scale so selected as to show upon a single sheet the entire project applied for, with the approximate location of all the principal works and lands referred to in paragraph (1)(*f*);

(*b*) a description of and a sketch showing the nearest neighbouring works or structures completed or in course of construction, both above and below the place of the proposed diversion, for diverting or using water for any purpose from the same source of supply and the approximate distance and direction of each such works from the proposed works;

(*c*) the names and locations of any other works or structures, including bridges, railways and canals, that might affect or be affected by the construction, maintenance or operation of the proposed works;

(*d*) the approximate discharge in cubic feet per second at or near the place of diversion of the river, lake or other source from which the water is to be diverted at high, medium and low water stages, respectively, together with copies of any existing measurements of the flow of the stream in the applicant's possession and a reference to all other such measurements of which the applicant has knowledge; and

(*e*) a brief outline of the undertaking in respect of which the licence is desired, including the use to which the power is to be applied, any sale, delivery or transfer thereof to other than the applicant that is contemplated, the territory, if any, within which such sale, delivery or transfer is to be exercised, the probable demand for power within such territory and an estimate of the capital cost of the entire undertaking.

(2) Toute demande doit être accompagnée des détails suivants:

a) d'un plan ou croquis préliminaire, préparé selon une échelle permettant de faire voir sur une même feuille l'ensemble du projet, ainsi que l'emplacement approximatif de tous les principaux ouvrages et terrains mentionnés à l'alinéa (1)*f*);

b) d'une description avec croquis des structures ou ouvrages avoisinants, les plus rapprochés, en amont comme en aval du lieu de la dérivation projetée, construits ou en voie de l'être en vue du détournement ou de l'utilisation, à une fin quelconque, de l'eau provenant de la même source d'approvisionnement; la distance et la direction approximatives de chacun de ces ouvrages avoisinants par rapport aux ouvrages projetés;

c) les noms et l'emplacement de ces ouvrages et structures, y compris les ponts, voies ferrées et canaux, susceptibles de nuire à la construction, l'entretien ou l'exploitation de l'entreprise projetée ou d'être entravés par cette dernière;

d) de données concernant le débit approximatif, en pieds cubes par seconde, à ou près de l'endroit de dérivation de la rivière, du lac ou autre source d'approvisionnement, d'où l'eau doit être dérivée, aux périodes d'eaux hautes, d'eaux moyennes et d'eaux basses, respectivement, de même que les données des mesurages antérieurs du débit du cours d'eau en la possession du demandeur, ainsi qu'une mention de tous les autres mesurages dont le demandeur a connaissance; et

e) d'un aperçu de l'entreprise faisant l'objet de la demande de concession, y compris l'usage auquel l'énergie est destinée; la vente, la livraison ou la transmission de cette énergie à des personnes autres que le demandeur; le territoire où, le cas échéant, cette vente, livraison ou transmission doit s'exercer, la demande probable d'énergie dans ce territoire, ainsi que le coût estimatif de l'ensemble de l'entreprise.

(3) Where the applicant is an incorporated company, the application, in addition to the information required by subsections (1) and (2), shall contain

(*a*) the names of the directors and officers of the company and their places of residence;

(*b*) the address of the head office of the company in Canada;

(*c*) the amount of capital authorized, subscribed, and paid-up, specifying in regard to paid-up capital, the amount paid in cash and the manner of payment for the balance;

(*d*) the proposed method of raising further funds, if required, for the construction and operation of the proposed works; and

(*e*) a copy of the special act of incorporation or the memorandum of association.

(3) Si le demandeur est une société constituée en corporation, la formule de demande doit contenir, outre les renseignements exigés par les paragraphes (1) et (2), les détails suivants:

a) les noms des administrateurs et fonctionnaires supérieurs de la société, ainsi que le lieu de leur résidence;

b) l'adresse du siège de la société au Canada;

c) le montant du capital-actions autorisé, souscrit ou payé, spécifiant dans le cas du capital-actions payé, la somme payée au comptant et le mode de paiement du solde;

d) la méthode à employer pour obtenir des fonds additionnels, si besoin en est, pour la construction et le fonctionnement des ouvrages projetés; et

e) une copie de la loi spéciale de constitution ou du memorandum d'association.

(4) Where the applicant is a municipality or municipal district, the application, in addition to the information required by subsections (1) and (2), shall contain

(*a*) the location, area and boundaries of the municipality or district;

(*b*) the approximate number of inhabitants in the municipality or district;

(4) Si le demandeur est une municipalité ou un district municipal, la formule de demande doit contenir les renseignements suivants, outre ceux exigés par les paragraphes (1) et (2):

a) la situation, la superficie et les limites de la municipalité ou du district municipal;

b) le chiffre approximatif de sa population;

(*c*) the present indebtedness and the borrowing limit of the municipality or district;

(*d*) a certified copy of any by-law or resolution passed by the municipality or district respecting the application or the undertaking to which the application relates; and

(*e*) a certified copy of any enabling Act or other statutory provision authorizing the municipality or district to engage in the proposed undertaking.

(5) All elevations given in connection with the plans or other information filed by any applicant shall be referred, if feasible, to mean sea-level datum.

(6) An applicant, when requested so to do by the Minister, shall file an affidavit setting forth such facts as may be required in respect of his financial standing and his ability to carry out the proposed undertaking.

(7) The Director may, at any time while an application is pending, notwithstanding any other requirement of these Regulations, require such additional plans, descriptions, measurements, specifications or other data, whether related directly or indirectly to the proposed works and undertaking, as he considers necessary, and those plans, descriptions, measurements, specifications or data shall be furnished by and at the expense of the applicant.

Publication and Hearings

4. (1) Upon request in writing from the Director, an applicant shall, at his own expense, publish a notice of the application in at least one issue of the *Canada Gazette* and in one or more issues of such other publications as the Director may specify.

(2) The notice shall be marked at the top in plain letters "Dominion Water-Power Application", shall be in a form approved by the Director, and shall give substantially the following information:

(*a*) the name and address of the applicant;

(*b*) the date of application;

(*c*) the name or a clear description of the source of water supply;

(*d*) a clear description of the place of diversion;

(*e*) the maximum horsepower capacity of the proposed plant;

(*f*) the nature of the undertaking and utilization of the power;

(*g*) a statement that the application has been filed with the Director, and that protests or objections may be filed by any interested party with the Director or at certain designated local points;

(*h*) when storage or pondage of water is contemplated, the place of storage, the capacity of the intended reservoir, and a general description of the lands that are to be flooded; and

(*i*) such other information as the Director may require.

(3) An applicant shall file proof of publication of the notice in the form of an affidavit, made by a person having knowledge of the publication, to which shall be attached a copy of the notice as published.

c) la dette actuelle et la limite d'emprunt de la municipalité ou du district municipal;

d) une copie certifiée de tout règlement ou de toute résolution adoptée par la municipalité ou le district municipal au sujet de la demande ou de l'entreprise visée par la demande; et

e) une copie certifiée de toute loi ou autre disposition statutaire autorisant la municipalité ou le district municipal à s'engager dans l'entreprise projetée.

(5) Toutes altitudes données concernant les plans ou autres renseignements fournis par un demandeur doivent, si possible, se rapporter au niveau moyen de la mer.

(6) Lorsqu'il en est requis par le Ministre, le demandeur doit fournir un affidavit exposant les faits qui peuvent être exigés relativement à sa situation financière et son aptitude à réaliser l'entreprise adoptée.

(7) Le directeur peut, en tout temps, alors qu'une demande est pendante, et nonobstant toute autre prescription du présent règlement, demander tels plans, descriptions, mesures, devis ou autres données supplémentaires, se rapportant soit directement, soit indirectement aux ouvrages et à l'entreprise projetés, qu'il juge nécessaires, ces renseignements devant lui être communiqués aux frais du demandeur.

Publications et enquêtes

4. (1) Dès que le directeur lui en a fait demande par écrit, le demandeur doit faire publier à ses propres frais un avis de sa demande dans au moins un numéro de la *Gazette du Canada*, ainsi que dans un ou plusieurs numéros de telles publications que le directeur pourra indiquer.

(2) Cet avis doit porter en tête, en lettres bien lisibles, les mots «Demande de force hydraulique du Dominion», être libellé selon une formule approuvée par le directeur et donner, en substance, les renseignements suivants:

a) le nom et l'adresse du demandeur;

b) la date de la demande;

c) le nom ou une description claire de la source d'approvisionnement d'eau;

d) une description claire du lieu de dérivation;

e) la puissance maximum en chevaux-vapeur de l'usine projetée;

f) la nature de l'entreprise et l'utilisation de l'énergie;

g) une énonciation portant que la demande a été déposée chez le directeur, et que toute personne intéressée peut déposer ses protestations ou objections chez le directeur ou à un endroit désigné;

h) s'il est projeté d'emmagasiner ou d'accumuler l'eau, l'emplacement et la capacité du réservoir projeté, ainsi qu'une description générale des terrains à submerger; et

i) tous autres renseignements que le directeur peut demander.

(3) Le demandeur doit fournir la preuve de la publication de l'avis, sous forme d'affidavit fait par une personne au courant de la publication et auquel doit être annexée une copie de l'avis tel qu'il a été publié.

(4) Following the completion of publication of the notice, a period of 30 days shall be allowed in which protests or objections may be filed with the Director.

(5) Where a protest or objection is filed within the period specified in subsection (4), or when for other reasons, the Minister considers that a hearing should take place before action is taken, he shall designate a time and place for the hearing and shall name a person to preside over and conduct the hearing.

(6) The hearing may be adjourned from time to time, and the applicant may be permitted for the time being to continue the preparation of his plans and the carrying on of investigations.

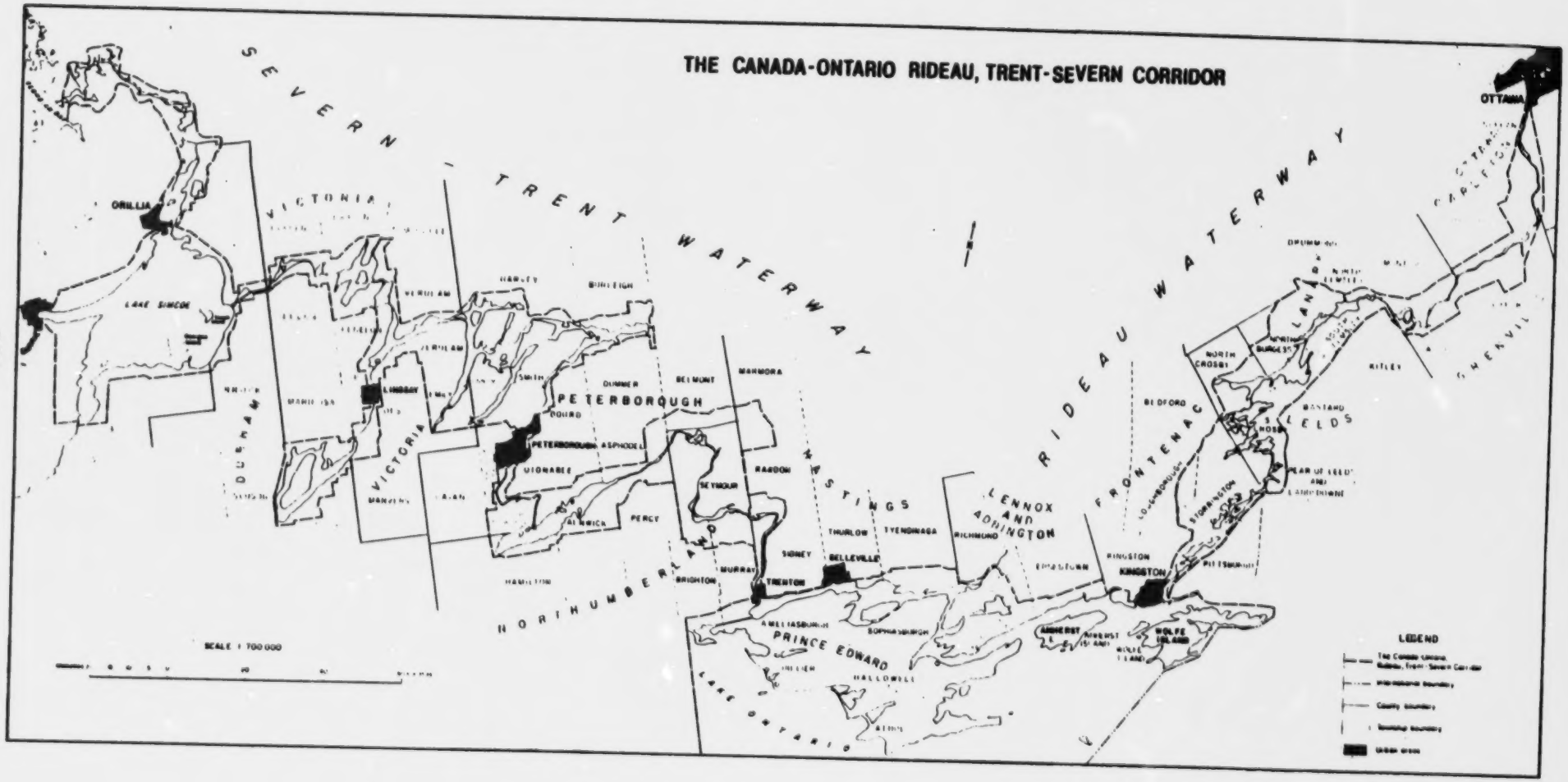
(7) The person conducting the hearing shall report his findings and recommendations in writing to the Minister, and the Minister may in his discretion reject the application if he deems it necessary in the public interest.

(4) A la suite de la publication de l'avis, on doit lais écouler une période de 30 jours durant lesquels on pou soumettre des protestations ou des objections au directeur.

(5) Si une protestation ou une objection a été soum durant la période de temps spécifiée au paragraphe (4), ou pour d'autres raisons, le Ministre considère qu'une enquête nécessaire avant que soit prise une décision, il désigne l'époc et l'endroit où cette enquête doit être tenue ainsi que personne qui doit la présider.

(6) L'enquête peut être ajournée de temps à autre, et demandeur peut avoir la permission, dans l'intervalle, de po suivre la préparation de ses plans ou de procéder à recherches.

(7) La personne chargée de conduire l'enquête doit faire rapport écrit de ses conclusions et recommandations au Mir tre, et celui-ci est libre de rejeter la demande, s'il le ju nécessaire dans l'intérêt public.


THE CANADA-ONTARIO RIDEAU, TRENT-SEVERN CORRIDOR
SEVERN - TRENT WATERWAY
RIDEAU WATERWAY
NORTHUMBERLAND
HASTINGS
LENNOX AND ADDINGTON
FRONTENAC
LEEDS
PRINCE EDWARD
VICTORIA
PETERBOROUGH
ORILLIA
LAKE SIMCOE
LINDSAY
PETERBOROUGH
BELLEVILLE
TRENTON
KINGSTON
OTTAWA
LAKE ONTARIO
SCALE 1:700 000
LEGEND

THE STATUS OF SMALL HYDRO IN QUEBEC

Paul M. Lavoie
Director, Electricity Branch
Quebec Department of Energy & Resources

I am going to talk today about the status of small hydro in Québec. First, I would like to look at what has been done in the last 10 or 20 years in this field. Then, I will describe the present state of affairs. This will be followed by an analysis of the situation to see if it should be changed and why. Finally, I will indicate what is envisaged in Québec even though no policy has been accepted yet.

HISTORIC SETTING

Small-scale hydropower is not a new source of energy, but unlike the newer technologies, such as photovoltaics and synthetic fuels, which await their crest on the learning curve, small facilities have been producing electricity for many decades. As a result, they were very important in the establishment and growth of many towns in Quebec and by 1932, the use of hydroelectric power in Québec had reached 674 MW of installed electric generating capacity. More than fifty plants owned by independent producers were in operation.

In April 1944, Hydro-Québec was formed after the expropriation of Montreal Light, Heat and Power Consolidated, the utility which controlled the distribution of electricity in the Montreal area. In 1963, all companies producing electricity and distributing it to the consumers were bought by Hydro-Québec. Those who were producing mainly for their own use were not nationalized: they were companies like Alcan, Maclaren and Abitibi Price. The producing facilities of municipalities were not nationalized either.

The creation of a large producing entity was not favorable to the development of small hydro facilities in the province. As you know, the demand for electricity was doubling each 10 years at that time and a enterprise like Hydro-Québec, which has to satisfy the demand of the whole province, looked at huge projects. They were more economical and, quite frankly, they were the best solution and, most likely, the only acceptable one. It was these circumstances that brought Hydro-Québec to build the Manicouagan-Outardes project and, more recently, the

James Bay project, Phase I which has an installed capacity of 10,192 MW.

As Hydro-Québec grew, it became less and less interested in small hydro sites and this is understandable. As you know, as an organization grows, it loses some flexibility which is essential to build and operate efficiently small hydroelectric stations. So it is not surprising to see that during the period 1963-1975, some nineteen (19) small hydro plants were decommissioned by Hydro-Québec. However, at the end of 1984, Hydro-Québec still had some 16 small hydro plants in operation with an installed capacity of 86 MW. In addition to that, five municipalities had 10 plants with an installed capacity of 21 MW. Finally, independent companies had 21 plants and an installed capacity of 97 MW. In summary, in Québec, there are 47 hydro plants with an individual capacity of less than 20 MW, for a total installed capacity of 204 MW. These facilities account for less than 0.2 % of total electric generation in Québec.

So, if we look at the last 20 years, we see that the number of small hydroelectric plants has been substantially reduced in Québec, going from 65 in 1963, to 47 in 1985.

In the same way, the relative importance of small hydroelectric production has been reduced substantially. As it is indicated by the following numbers; in 1963 we had some 266 MW of small hydro for a total installed capacity of 10,365 MW. In 1985, small hydro represented only 204 MW of a total of 29,161 MW, including Churchill Falls. I don't have similar figures for other provinces or states, but I am convinced that Québec is not the only province or state to have experienced, in the last few years, an absolute and relative decrease of small hydroelectric status in its production mix.

This trend reflects the advantages of large hydroelectric projects in comparison to small ones, at least in the situation that prevailed during that period. The question is whether we should try to modify this trend, and how to do it, should we decide that it is appropriate?

1. THE SMALL RIVER POTENTIAL

In order to determine whether or not we should try to modify the trend of the last 20 years, let's look first at what we have to develop. We still have 14,000 MW of unharnessed economical hydroelectric potential on large rivers, that is, rivers of 100 MW or more. This is a very conservative estimate that was done a few years ago and it has been established that these 14,000 MW would be less expensive to develop and operate than a nuclear station. We feel confident that if such an estimate were to be done today, the economical potential of our large river would be substantially increased.

At the present time, we have only a rough estimate of our small hydroelectric potential. We estimate that the potential of rivers having an individual potential of less than 100 MW, but higher than 1 MW, is 10,000 MW, but we don't have a breakdown of this potential by size category. For example, we do not know the potential of rivers with an individual potential of less than 20 MW which is what we usually refer to when we are talking about small hydro.

However, of this total potential of 10,000 MW, about 5,000 MW have been studied more closely by private companies prior to the nationalization, or by Hydro-Québec later on. In fact, about 300 sites have been identified and considered economical. This is not negligible.

Thirty-nine of these sites are located in isolated areas on the North Shore of the St-Lawrence River and in the northern part of the province, that is the James Bay, the Hudson Bay and the Ungava Bay areas.

The remaining small hydroelectric sites on small rivers is located in "populated" areas and some of it could be developed using existing structures.

There is no doubt in my mind that the potential of small rivers should be developed in isolated areas to replace diesel production, whenever this is economical. Hydro-Québec is studying very closely many sites and may propose the construction of some facilities in the near future. At the present time, a final decision is being prepared concerning the construction of a 21 MW plant at lac Robertson in the North Shore to feed 15 villages in the area. Similar projects may prove advantageous to replace the 12 small diesel-generating stations located in remote northern areas.

A small project has already been completed in this area by the Crees of Wemindji. They built a 1.1 MW station for $6.5 million, that is, $5,900 per installed KW compared to $1,500 for La Grande Phase I. This latter figure includes the transportation cost to Montréal.

The two above-mentioned projects indicate some of the problems that will be encountered in developing small hydro project in remote areas. In the case of the lac Robertson, we will have to deal with the rights of native people. This work has not been completed yet and we do not know what it may involve in terms of costs or other constraints.

The Wemindji project indicated that small hydro is very expensive and this is very important in view of the fact that the price of oil may decrease substantially. Projects that were economical when oil sells at $30 a barrel may not be economical at $20.

Furthermore, the Wemindji projects illustrate the fact that the need of a remote community and the potential of a nearby river do not always match. As you may know, this station will not be able to provide electricity for heating and another source of energy will have to be maintained.

In the populated areas of Québec served by Hydro-Québec, the economic viability of small hydro is less evident. It is expected that small plants owned by companies and municipal utilities will be maintained because of the low cost of the energy produced. However, new installations may have difficulty meeting the cost of large systems unless they possess special advantages due to low capital costs (renovation of existing sites or civil works already done).

In developing a proposal, the appropriate approach is therefore to encourage private generation by outlining the terms for a safe interconnection with the provincial power system and offering rates for electricity purchases that would be beneficial to private generation owners and to Hydro-Québec's customers.

Ideally, the rate level must not be so high as to negate the benefits to the utility, or so low as to remove the incentive for the customer to generate and sell. Also an economical inducement is required for both the seller and the buyer, but any customer whose economics of generation lie above those of Hydro-Québec, has dubious justification for existence on a cost/benefit basis.

As many small hydro plants were decommissioned by Hydro-Québec and interesting sites are available across the province, private developers are showing growing interests in revitalization of small hydropower. They are waiting for a clear development policy, notably concerning the rate structure and some government programs, to jump into the small hydro business.

2. PROCEDURE SIMPLIFICATION

An important factor in determining the feasibility for a small-scale hydroelectric development is the institutional setting. A developer must meet numerous requirements and most of which involve approval by, or interaction with, a government ministry. Thus, the organizational structure of governmental entities, their degree of coordination or the existence of an agency specifically designated to assist in small-scale hydroelectric development, all can affect the chances for project implementation.

Presently, potential developers unfamiliar with governmental workings may face a frustrating search for the many individual departments having partial responsibility in project approval. In fact, Québec does not have a designated lead agency or ministry.

At the present time, the developer must obtain an authorization from the Ministry of Environment and from the Ministry of Energy and Resources. The Ministry of Environment has responsibility for ensuring that projects are acceptable from an environmental point of view. For this purpose, a procedure has been put in place and it is basically the same for all projects over 10 MW. It may be appropriate to see if we can simplify this procedure. It should not be necessary to do the same type of study for a small project than for a large one, like the James Bay project.

The Ministry of Environment requires that the developer provide detailed technical data. We will examine the possibility of simplifying these requirements for small projects, especially for those installed on existing structures.

The developer must also obtain from the Ministry of Energy and Resources a lease to harness a small hydroelectric site. When the potential of the site is over 225 kW, a special law of the Québec Legislature is needed. This procedure is time-consuming and it might be appropriate to change this ceiling.

These requirements use a developer's valuable time and other resources, increasing the cost of the project.

Futhermore, when producing electricity from a small hydroelectric plant, a developer has to pay water rights. In 1985, if the site is on a public one, he has to pay $1.39 per thousand kilowatt hours*.

In order to encourage small hydro systems and simplify the administration, it may be possible to remove water rights on plants with an installed capacity of 10 MW or less.

3. FINANCIAL

Financing is a crucial factor in small-scale hydroelectric development. A small facility of less than one megawatt in capacity can cost over $5 million. Estimates of initial investment required for a small-scale hydro facility range from about $5,000 to $7,000 per kilowatt.

The high costs of hydroelectric development require that a developer borrow considerable sums of money. Today, no financing mechanism exists for a private developer other than conventional financing at market interest rates. Futhermore, developers are unable to market their electricity, or when they find a willing purchaser, the prices are too low to generate a profit. To make a project viable, private developers are expecting at least an internal rate of return of 15% on a 15-year basis.

---

* This is the general case. Variations are possible.

As indicated above, it does not seem appropriate at this time to allocate public funds to finance such projects, but it would certainly help private developers to get financing if we could get Hydro-Québec to purchase the electricity involving long-term contract with a reasonable price.

CONCLUSION

In summary, the potential of small rivers in Québec, however defined, is substantial. In the last few years, we have seen the decommisioning of many small hydro plants. This may seen surprising at first glance, but when we examine the situation more closely, we realize that in Québec, the economics of small hydro plants is not conclusive to an accelerated and general development of that resource. This is due to the fact Quebéc still has a huge, unharnessed potential that is generally more economical than small rivers.

Consequently, we do not feel that it would be appropriated to allocated public funds to accelerate the development of small hydro plants rather than large ones. However, small hydro plants can be very sound in remote areas.

Other small hydro electric projects are viable, especially those using existing structures and we have the intention of reducing and simplifying the governmental requirements. Furthermore, we will encourage Hydro Québec to put forward a buying policy which should make these projects more economical and greatly facilitate their financing.

Paul M. Lavoie is Director of the Electrical Section in the Quebec Ministry of Energy and Resources. Before joining the Ministry of Energy and Resources Mr. Lavoie previously worked with the Federal Government and Hydro Quebec. He has been with the Quebec Government since 1982.

U.S. SMALL HYDRO EXPERIENCE

U.S. POLICIES ENCOURAGING SMALL HYDROELECTRIC DEVELOPMENT: AN OVERVIEW

ROSS D. AIN
Van Ness, Feldman, Sutcliffe & Curtis
Washington, D.C.

It is indeed a pleasure to be here and I am going to apologize ahead of time for having to run to catch a flight at 3:00. I will therefore try to make my formal presentation short enough so that I will have some time to entertain questions. Generally, I find responding to your specific questions more illuminating than trying to guess at your real interests while plodding through my prepared remarks.

I would like to give you a brief background of the recent re-emergence of the small hydro industry in the United States. After giving you a brief overview of the U.S. experience, I will focus on a few topics that appear to be of interest to you based upon remarks I have heard last night and earlier today.

We first became interested in redeveloping small hydro in the United States as a result of our experience during and after the 1973 oil embargo. At that time, the U.S. was exposed to energy supply interruption and curtailment because of a high dependence on foreign oil and declining natural gas reserves. In 1977, both President Carter and the Congress felt small hydro development at existing dams, many with retired units, involved few environmental problems and would help reduce dependence on foreign oil. As a result, a program of incentives for private development of small hydroelectric facilities was implemented as part of the National Energy Plan, enacted into law in 1978.

The National Energy Plan, as passed by Congress, was a massive piece of legislation designed to reduce our dependence upon foreign oil. Included in the legislation were provisions that required the conversion of utility plants from oil and gas to coal, prohibited new oil and gas burning facilities from being built, established a systematic conservation program, allowed tax credits for research and development of non-oil and gas technologies, including small hydro development, and finally, created a program of incentives for private develop- ment of alternative sources of electric generation -- a program now commonly known as the "PURPA" program. The acronym "PURPA" stands for the Public Utility Regulatory Policies Act of 1978.

The Act contained a number of types of incentives, not all of which proved effective. First, a small hydro loan program was established that provided loans for feasibility studies. However, the program was always underfunded and few projects really took advantage of it. In my view, it was not a rousing success. PURPA also required the Department of Energy to create a national inventory of hydro sites which was of great assistance to developers who used it as a resource. The Congress also told the Federal Energy Regulatory Commission (FERC), our "one-stop" hydroelectric project licensing agency, to simplify and expedite licensing proceedings by cutting back on the paperwork burdens and simplifying the regulations. Finally, sections 201 and 210 of the Act establish unprecedented incentives for private development of small power production and cogeneration facilities. These incentives gave certain types of private electric producers the right to interconnect with the local utility, required the utility to purchase the power at its incremental cost of generation (avoided cost), and exempted the private producer from regulation as an electric utility. Hydroelectric projects up to 30 MW in size were one of the eligible types of electric generation facilities under the PURPA program. Private developers soon began to position themselves to take advantage of the incentives by initially scouring the country for viable hydroelectric sites.

I think without question that of all the programs in PURPA, the section 201 and 210 program proved to be the most effective -- indeed, it exceeded all reasonable expectations. The U.S., between 1978 and 1985, experienced an explosion of interest in hydroelectric development. Applications for preliminary permits, which give the holder the right to study a project for a period of time free from competition but do not allow for construction, increased from 9 in 1977 to 501 in 1980, to 1,856 in 1981. Applications to actually construct projects -- license applications -- increased from 30 in 1977, to 73 in 1980, to 738 in 1982. Today, the peak is probably over and the applications have levelled off, but they remain at quite a high level, compared to what they were in the seventies.

It is important to note, however that thousands more projects were proposed than will ever be built, but many hundreds may ultimately be built. Over 160 small hydroelectric projects have been placed in service since 1978 with a total capacity of around 300 megawatts.

From 1977 to 1980, there was consistent Congressional and Administration support at the federal level for small hydro. However, state and federal environmental agency reaction to all of this development was mixed. First of all, small state environmental agency staffs were overwhelmed with the review obligations that were placed upon them by the FERC regulations. The agencies felt that they were being imposed upon; they began to object to the short opportunity they had to perform their environmental reviews and great delays resulted.

Finally, private environmental groups began to recognize that the large number of projects that were being proposed could create environmental problems. The heightened adversarial relationship between hydro developers and environmental interests lead to numerous legal challenges that have served to significantly cool the pace and enthusiasm for development. Among the issues that have been litigated are:

1) the need to do cumulative impact assessments when more than one project is proposed in a river basin;

2) the definitions of "existing dam" and "natural water feature";

3) FERC procedures for complying with the National Environmental Policy Act (NEPA);

4) limitations on duplicative state regulation of hydroelectric projects in the face of comprehensive federal regulation by the FERC; and

5) the degree to which other federal agencies can condition a license issued by the FERC on federal land.

With the current low oil price, Congress has been susceptible to pressure from environmental groups to eliminate incentives for private hydro development. The energy tax credits for hydro were not extended in the House of Representatives' December tax reform bill; although the energy tax credits for solar and geothermal projects were extended. There have been proposals to limit the benefits of PURPA to projects at existing dams and not allow such benefits to extend to "natural water feature" projects. There have been proposals to amend the Federal Power Act to add additional environmental protection provisions that the FERC must impose upon licensees.

In the face of this environmental opposition, over the next few years I expect there to be a concentration of interest on the remaining existing dam projects, particularly the water supply, irrigation, flood control or navigational dam facilities in the U.S. Developers are more than ever before having to make a larger upfront commitment to analyze environmental issues early in the development process, but those developers willing to make that investment and satisfy environmental concerns early in the process should be successful.

In addition to environmental considerations, the other issue that is very important is economics. Small hydro may look nice and be environmentlly benign, but it has to be economic both for the developers and the ratepayers. If it is not economic right now, based upon short-run avoided energy costs to Ontario Hydro, it may be economic in five years at rates which reflect a proposed capacity addition that Ontario Hydro would build, but for small hydro development. Developers always have to make the case that a particular project is economic and, in the United

States, we have more than five years of experience under PURPA in methodologies and contractual arrangements to do that. The availability of long term contracts at levelized rates - that is, rates that are front-end loaded to allow adequate revenue to retire debt, but which do not escalate in later years -- have probably proved to be more important than the precise level of avoided cost rates available to developers at any point in time.

What has been the utility reaction to the PURPA program in the United States? Most everyone in the audience has thoughts about what the utility reaction is and will be up here and I have heard a number of discuss ions on that. In the United States, it is a much more interesting game for utility management today than it was six or seven years ago. It is more complicated, more difficult, in some ways more treacherous, but, whether or not they will admit it, PURPA has given utilities breathing space. Breathing space to not have to go to the market to finance capacity additions at high marginal rates of interest. It has given them time to look at where demand is really going in the long term - after the various oil price shocks have translated their effects through the economy. It has given them time to build up their capital structure, to improve their coverage ratios and to be, in a sense, stronger economically than they have been since the 1960's. PURPA may not be the only contributor to this state of affairs, but certainly it was and is a major contributing factor. Many utilities have even set up deregulated subsidiaries to take advantage of the PURPA program.

The PURPA program has brought competition into the marketplace for generation capacity additions. This competition has invigorated the utility industry; although, as was said, it has not done all of the good its proponents claim, but neither has it done all the evil its detractors would have you think.

It is a pleasure for me to be here in Toronto today and to share these observations with you. I would be delighted to take a few questions. Thank you.

QUESTIONS AND ANSWERS

Q. I have a short question for you. On the levelized rates, you talked about, could you tell me who is doing levelized rates in the States and how long a period they look at when they talk about levelized rates?

A. I think you will find that it is quite a pervasive phenomenon in the United States. California may have started the trend; California is normally a bit ahead of the curve in terms of dealing with these types of issues. They came up with a set of standard contracts in which the developer agreed not to ask for more in the future and the utility agreed not to pay him less regardless of actual avoided costs over the 20-year term of the contract.

A second type of levelized contract is referred to as a banked account-type contract. Niagara Mohawk, for instance, enters into these. The contracts measure the amount by which the levelized rate exceeds actual avoided costs in the early years and the utility takes that amount as a security interest in the project until the amount is effectively paid back in the latter years when the rate is below actual avoided costs. So there are different ways of doing it, but in New York, in California, all over the country, you see levelized rate contracts.

Q. Is it your answer then that about 30 years is the maximum you have seen around?

A. I have not seen levelized rate contracts that actually go much beyond 20 years.

Q. Could you please tell us what chances Canadians have to go down there to the United States and develop hydroelectric sites.

A. You must be a U.S. citizen to hold a license under the Federal Power Act for a hydro project. However, that includes corporate citizens. So, if you incorporate in the United States, you can get around that problem. The stockholders do not have to be U.S. citizens.

Ross D. Ain served as Chief Counsel to the U.S. House of Representatives Energy Committee during the period when incentives for small hydro were enacted by Congress, and was one of the principal authors of PURPA. Subsequently, he was Associate General Counsel for FERC in charge of implementing the PURPA and small hydro regulatory programs. Mr. Ain is presently with the Washington D.C. law firm of Van Nese, Feldman, Sutcliffe and Curtis.

PATTERNS OF HYDRO DEVELOPMENT IN THE UNITED STATES

Carol H. Cunningham, P.E.
Director of Water Resources
Morrison-Knudsen Engineers

In 1978, hydropower development in the United States underwent a radical and sweeping change --- or so it seemed. By enacting the Public Utilities Regulatory Policies Act, or PURPA, the Congress of the United States in one stroke created a new market for hydropower development, opening the field to private developers, industrial concerns, and municipal entities. Prior to 1978, electric utilities, by law, had a virtual monopoly on hydro development, but under PURPA, that was no longer the case. The new law, along with U.S. Department of Energy regulations and programs related to it, explicitly encouraged the participation of private developers and other non-utilities in supplying the nation's need for renewable energy resources.

The purposes and effects of PURPA will be discussed in greater detail later, but for now the key point is the climate of expectations that was created by the demonopolization of hydro development. In 1978 and in subsequent years, the new government policies created what was then described as a "gold rush" climate for non-utility developers. Opportunities to develop, sell, and even make a profit on hydroelectric energy were thought to be almost limitless, considering the thousands of potential hydro sites throughout the United States. Not unexpectedly, in the years following 1978, large numbers of private and other non-utility developers appeared on the scene, each trying to exploit these newly perceived opportunities quickly and profitably. In a real sense, a whole new industry was born.

The new hydropower industry born in 1978 is still unquestionably alive --- but its track record of the past eight years falls considerably short of the expectations that many held for it at its creation. Eight years cannot be considered a long period of time, yet there is ample evidence to demonstrate that hydro development by private developers and other non-utilities has not come anywhere near displacing the dominant role played by electric utilities in the creation of hydroelectric energy, despite the implementation of PURPA. This paper will summarize hydropower development patterns of

the past eight years, focusing on the major problems encountered by non-utility developers that help explain why the expected "hydro gold rush" never quite materialized, and will offer a scenario of hydro development in the United States over the next several years.

PURPOSES AND EFFECTS OF PURPA

In 1978, the United States, along with the rest of the world, was deep in the throes of an "energy crisis". Acting to offset the effects of rising prices of oil and other fossil fuels, the U.S. government formulated policies designed to encourage and assist the development of alternative energy sources, particularly those that were renewable. PURPA was one of five parts of the National Energy Act, designed to reduce dependence on foreign oil. It provided incentives to developers of small-scale hydroelectric projects by (1) exempting developers from regulation as public utilities and (2) requiring utilities to purchase the power produced by such facilities at a price not to exceed the utilities' avoided cost as determined by state public utility regulatory commissions. PURPA also authorized the Federal Energy Regulatory Commission (FERC) to establish simplified rules for the licensing of small hydro projects. At the same time, the U.S. Department of Energy established grant and low-interest loan programs to assist with the feasibility study, licensing, and development of small hydro projects. Later, the Energy Security Act of 1980 allowed FERC to exempt certain projects from portions of the Federal Power Act.

Tax incentives were also implemented in an effort to further stimulate small hydro development and, thus, implement federal energy policy. Tax incentives took the form of energy tax credits enacted by the Crude Oil Windfall Profit Tax Act of 1980 (COWPTA), which was modified by the Economic Recovery Tax Act of 1981 (ERTA) and the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA). In addition, ERTA enacted and TEFRA modified a new depreciation alternative, the Accelerated Cost Recovery System (ACRS), which allowed more rapid depreciation of qualified property brought into service after 1980.

The effect of the many institutional and legal changes was to create a market for electricity produced at small hydro facilities in which the price assumed a commodity value as opposed to the traditional method of setting electric rates based on the cost of service plus a reasonable rate of return. The impact of these various incentives, as measured by the increased interest in the development of small hydro electric facilities by entrepreneurs, industrial concerns, and non-utility municipalities, as well as by utilities, was pronounced. Until 1978, an abandoned dam site was viewed only as a liability; and many owners, including utilities, transferred these sites to the local government or a state agency. But with PURPA, many of these dams came to be

considered valuable assets; and various parties, in effect, staked out claims by filing for a license from FERC to acquire the right to develop the hydropower potential of these formerly abandoned dams.

Suppliers of services and equipment to the hydro market also had a significant reaction. Engineering firms developed techniques to deal with small hydro projects in a cost-effective manner, and assembled teams capable of designing small hydro facilities. Turbine-generator equipment suppliers developed "pre-designed", standardized lines of equipment that allowed the cost of engineering to be spread out over a number of units, thereby reducing the unit price. In addition, major foreign suppliers entered the U.S. market, resulting in a broader range of available equipment and more competition. The overall effect of these changes was that equipment prices tended to decrease while overall efficiency increased. As a final boost to development, the regulatory climate in the late 1970's and early 1980's was relatively hospitable to new hydro development. The federal licensing process was streamlined, and many projects won approval from FERC in less than a year after the initial application for license was filed.

Clearly, circumstances favoring a shift from hydro development primarily by utilities to substantial development by non-utilities could hardly have been more favorable. But what results did this favorable set of circumstances produce?

TYPES OF HYDRO DEVELOPMENT

To determine the patterns of hydro development since the passage of PURPA, a list of all hydro projects that have gone on-line in the United States between January of 1980 and December of 1985 was obtained from FERC and analyzed for significant information. The starting point of 1980 was chosen as the earliest year that any significant number of non-utility sponsored projects could have become operational, given a reasonable time for planning, licensing, design, and construction between the passage of PURPA in 1978 and the beginning of 1980.

A total of 268 hydro projects became operational during this six-year period, representing more than 2.5 million kilowatts of hydroelectric generating capacity. Five basic types of project developer were represented:

- Private developers, accounting for 144 projects, or 54 percent;
- Industrial developers, accounting for 28 projects, or 11 percent
- Municipal developers, accounting for 33 projects, or 12 percent;

- o Utilities, accounting for 57 projects, or 21 percent;
- o Miscellaneous types of developers, primarily "hybrids" between private developers and municipalities or utilities, accounting for 6 projects, or 2 percent.

Private developers accounted for more than half of all projects; yet these projects represented only about 133,000 kilowatts, or about 5 percent, of the total of 2.5 million kilowatts of installed capacity. On the other end of the spectrum, utilities accounted for nearly 1.9 million kilowatts out of the total capacity of 2.5 million, or nearly 80 percent. Table 1 shows the percentages of total installed capacity for each type of developer.

These statistics are revealing, but are also in one sense misleading. Of the 268 projects, only 11 were of more than 25,000 kilowatts of installed capacity --- but these 11 projects accounted for almost 2 million kilowatts, and included one project that by itself was more than 1 million kilowatts. Moreover, of these 11 projects, ten were developed by electric utilities.

TABLE 1

U.S. HYDRO PROJECTS IN SERVICE, 1980-1985

Developer Type	Number of Projects	(%)	Total Installed Capacity (kW)	(%)
Private	144	(54%)	132,894	(5%)
Industrial	28	(11%)	69,595	(3%)
Municipality	33	(12%)	121,848	(5%)
Utility	57	(21%)	2,175,438	(87%)
Miscellaneous	6	(2%)	3,701	(0%)
Total	268	(100%)	2,503,476	(100%)

Notes:

1. The second number in each column represents the percentage.
2. Data for 1985 incomplete.

In distinguishing between "large" hydro and "small" hydro in this paper, a small hydro project is defined as one of less than 25,000 kilowatts of installed capacity. For the purposes of this analysis, it is therefore appropriate to exclude the 11 large hydro projects, and to re-examine the figures to

determine the impact of different types of developers. Table 2 shows the breakdown of the 258 small hydro projects. Not unexpectedly, the percentage of total installed capacity represented by private developers has increased --- but only to about 24 percent, even though private developers were responsible for 56 percent of all small hydro projects. Utilities continue to account for a disproportionate share of total installed capacity --- 53 percent, despite developing only about 18 percent of the projects.

TABLE 2

U.S. HYDRO PROJECTS IN SERVICE, LESS THAN 25 MW, 1980-1985

Developer Type	Number of Projects	(%)	Total Installed Capacity (kW)	(%)
Private	144	(54%)	132,894	(24%)
Industrial	28	(11%)	69,595	(13%)
Municipality	32	(13%)	47,848	(9%)
Utility	47	(18%)	292,458	(53%)
Miscellaneous	6	(2%)	3,701	(1%)
Total	257	(100%)	546,496	(100%)

Notes:

1. The second number in each column represents the percentage.
2. Data for 1985 incomplete.

Underscoring these figures are statistics showing the sizes of the projects represented by each classification of developer. Of the 144 projects by private developers, 103, or more than two-thirds, were less than 1,000 kilowatts in installed capacity, and only three were greater than 5,000 kilowatts. Of the 47 utility-developed small hydro projects, on the other hand, only 13 were under 1,000 kilowatts, and 17 were of 5,000 kilowatts or greater. These breakdowns, as well as average project sizes by developer type, are shown on Table 3.

All of these trends are evident when the data is analyzed on a year-by-year basis from 1980 through 1985. Table 4 shows that even though the number of operational projects changed significantly from year to year, utilities continuously accounted for a disproportionate share of the installed capacity of the small hydro projects that went on-line in each year, while private developers were responsible for a large share of the projects which nevertheless tended to be of very small size.

TABLE 3

INSTALLED CAPACITIES OF U.S. HYDRO PROJECTS, 1980-1985

Developer Type	Number of Projects by Size				Average Installed Capacity (kW)
	Less than 1 MW	1-5 MW	5-25 MW	Greater Than 25 MW	
Private	103	38	3	0	923
Industrial	16	8	4	0	2,486
Municipality	19	11	2	1	3,692
Utility	13	17	17	10	38,166
Miscellaneous	5	1	0	0	617
Total	156	75	26	11	9,341

Note: Data for 1985 incomplete.

The analysis of this data leads to some obvious conclusions: first, that development of "large" hydro projects has primarily remained the exclusive domain of utilities; second, that even the development of small hydro has been dominated by utilities, PURPA's provisions to the contrary notwithstanding. The impact of private developers is evident only in the category of very small hydro projects of less than 1,000 kilowatts, which have contributed only a tiny fraction of the hydroelectric capacity developed between 1980 and 1985. This fact may be related to the PURPA provision that requires utilities to purchase power from qualifying facilities; arguably, many very small projects would not have been economical for the utilities to develop themselves, but were feasible from a private developer's point of view given that utilities are required to purchase the power at their avoided cost.

PROBLEMS OF PRIVATE HYDRO DEVELOPMENT

Over the past three years, Morrison-Knudsen Engineers has participated in the Small Hydro Technology Transfer Project, under contract to the U.S. Department of Energy and the Electric Power Research Institute. Our responsibilities for this project have included an in-depth analysis and summary of the results of various federal programs of the late 1970's and early 1980's designed to assist and encourage small hydro development in the United States. Our analysis has covered feasibility studies and licensing as well as the important aspects of actual project development such as financing, power sales, construction contracting, and operation and maintenance. From this project, as well as from our experience in providing hydro facility engineering services, we have identified key

TABLE 4

U.S. HYDRO PROJECTS IN SERVICE YEAR-BY-YEAR, 1980-1985

(LESS THAN 25 MW)

Developer Type	1980				1981				1982			
	Number of Projects		Installed Capacity (kW)		Number of Projects		Installed Capacity (kW)		Number of Projects		Installed Capacity (kW)	
Private	3	60%	3,950	50%	9	40%	19,850	38%	19	43%	8,677	11%
Industrial	0	0%	0	0%	11	50%	13,177	26%	4	9%	4,968	6%
Municipality	0	0%	0	0%	1	5%	410	1%	8	18%	9,643	12%
Utility	2	40%	3,900	50%	1	5%	18,000	35%	10	23%	52,980	69%
Miscellaneous	0	0%	0	0%	0	0%	0	0%	3	7%	1,036	2%
Total	5	100%	7,850	100%	22	100%	51,437	100%	44	100%	77,304	100%

Developer Type	1980				1981				1982			
	Number of Projects		Installed Capacity (kW)		Number of Projects		Installed Capacity (kW)		Number of Projects		Installed Capacity (kW)	
Private	45	58%	28,002	17%	48	64%	47,664	27%	20	58%	24,761	38%
Industrial	3	4%	1,800	1%	9	12%	49,350	28%	1	3%	300	0%
Municipality	9	12%	18,330	11%	6	8%	11,020	6%	8	24%	8,445	13%
Utility	19	25%	119,228	70%	10	13%	65,580	38%	5	15%	32,770	49%
Miscellaneous	1	1%	1,492	1%	2	3%	1,173	1%	0	0%	0	0%
Total	77	100%	168,852	100%	75	100%	174,787	100%	34	100%	66,276	100%

Notes:

1. The second number in each column represents the percentage.
2. Data for 1985 incomplete.

problem areas that have resulted in difficult and sometimes insurmountable obstacles to successful hydro development since the passage of PURPA. These key problem areas include Planning and Feasibility Analysis; Licensing and Environmental Issues; Power Sales; and Project Financing.

Planning and Feasibility Analysis. A surprisingly large number of developers have gotten started on the wrong foot due to inadequate project planning and feasibility studies that failed to address key development issues and that consequently painted an overly-optimistic picture of project development. Our review of 240 Department of Energy-assisted feasibility studies showed that while issues related to technical feasibility, such as project configuration and potential capacity, were unusually dealt with satisfactorily, non-technical considerations were often either addressed inaccurately or not addressed at all.

Frequently-encountered areas of deficiency in these studies included:

- Project Financing. In many instances, no financing plan was presented at all, or the costs of financing were not included in the economic analysis of the project. Many studies did not identify the rationale for selecting interest rates or terms of loans, or consider such issues as negative cash flow. Clearly, the absence of such information would have had a substantial negative impact on the planning of and expectations for a project.

- Value of Power and Marketing. A disconcerting number of studies failed to determine whether or not potential markets for a project's power actually existed. Other significant errors were related to the rates used to escalate the value of energy over the life of the project; these often were unrealistically high and acted to paint an overly-rosy picture of project cash flow and profitability.

- Transmission and Interconnections. Many studies neither reported nor accounted for the utility's interconnection requirements, and most failed to discuss whether or not the local utility line could accommodate the additional load resulting from the proposed project.

- Cost Estimates. Many cost estimates were incomplete, failing to account for land acquisition, interconnection, contingencies, or escalation. Omitting or inaccurately estimating major cost items obviously had a negative impact on a realistic feasibility assessment of project development.

- Environmental Considerations. The studies frequently did not discuss environmental issues adequately, failing both to identify potential impacts and to account for necessary mitigation measures and their associated costs.

- o Institutional Considerations. Often, there was a lack of familiarity with the FERC licensing and permitting process, which resulted in unrealistic projections of the time schedule for project development.

- o Annual Energy Generations. Accuracy in estimating energy generation is particulary vital in small hydro projects. Yet many feasibility study energy estimates were too high, failing to account for such factors as head losses, equipment efficiencies, station use, or outages. In some cases, inappropriate stream gage data were used.

Inaccuracies or deficiencies in any of the key problem areas mentioned above have the potential for presenting a highly distorted view of project feasibility. It is not unreasonable to assume that many private would-be developers, inexperienced as they were in the years immediately following the passage of PURPA, were misled by the findings of feasibility studies prepared by equally inexperienced consultants. As the development process proceeded, many projects initially thought to be feasible were either significantly scaled down or abandoned altogether.

Licensing and Environmental issues. Even though PURPA provided for more streamlined federal licensing procedures through FERC, the licensing process has from the beginning proved to be a difficult challenge for many hydro developers. MKE studied 41 licensing applications that had been submitted to FERC in the late '70's and early '80's, and found that at least one-third of them contained errors or deficiencies of sufficient magnitude to considerably delay FERC approval for the project. These errors and deficiencies could and should have been avoided by the applicants; the fundamental problem was that the applicants simply failed to understand or follow written rules and procedures that FERC had already prescribed.

The FERC licensing process requires an applicant to consult with a significant number of federal and state government agencies whose concerns are to protect the environment. Consultation, under FERC rules, means that these agencies should be fully informed about the project and its potential environmental impacts, and should have the opportunity to comment on the proposed development scheme. Not infrequently, these comments take the form of substantive recommended changes in the project that, if implemented, may affect both its construction costs and its energy production. Needless to say, developers are usually not particularly pleased at the thought of changing their development plans, particularly when the changes will negatively affect project economics; nevertheless, the consultation process is a fact of life of hydro development in the United States, and developers who attempt to ignore or circumvent consultation requirements risk major delays as well as significantly increased paperwork and costs that have, in some instances, resulted in the indefinite postponement of project development.

Even under the best of circumstances, FERC licensing can be an uncertain, time-consuming, and costly process. Many developers who encountered major licensing difficulties, however, could have saved themselves considerable trouble simply by following the rules and taking consultation requirements seriously.

It should be noted here that FERC procedures and policies have been continuously evolving since the passage of PURPA such that, at present, it is considered much more difficult to win expeditious project approval. Licensing procedures and consultation requirements have now become more detailed and stringent than in the past --- a fact that is not encouraging for would-be hydro developers, particularly those who are inexperienced and unfamiliar with the practical requirements of development.

Power Sales. A key provision of PURPA was to require utilities to purchase the power from small hydro projects at their avoided cost. As favorable to private developers as this requirement might appear, it in no way automatically guaranteed a market for power produced by a hydro project. For example, PURPA did not require utilities to extend favorable power sales terms to developers that would account for negative cash flow during the early years of the project's life, nor did it set any uniform standard for utilities to calculate and substantiate their avoided costs. As a result, the power sales climate varies significantly from state to state and region to region within the United States. In general, it has been easier to negotiate a favorable power sales agreement in Northern California and the Northeast because of higher avoided costs and more pressing energy requirements than in the Northwest and Southeast; but in the final analysis, the power sales process has been on a case-by-case, utility-by-utility basis.

The process was further complicated in earlier years by developers who assumed, erroneously, that PURPA was all they need to successfully sell their power. Their lack of sophistication and inexperience often led to lengthy and unconstructive negotiations, with delays that in turn affected both project licensing and project financing. These problems and delays could have been avoided in many instances if developers, with competent professional help, had made a thorough survey of potential markets, carefully researched avoided cost data, familiarized themselves with state regulations governing utilities, and accounted for important technical considerations such as interconnections and transmission requirements.

It should be remembered that the power sales climate was most favorable to developers when the cost of oil and other fossil fuels was high, resulting in high avoided costs for utilities and provisions for comparatively high escalation rates in

long-term power sales agreements. Now, of course, the economics of energy have changed, with the falling price of oil providing less and less incentive for utilities to extend favorable prices on contract terms to hydro developers.

Project Financing. This key problem was and continues to be a decisive factor in private hydro development. With few exceptions, these developers did not have sufficient credit to support "balance sheet" financing of project construction. Consequently, the only available financing has been that which is backed by the project itself, that is, secured by the stream of revenue to be produced by the project. For this type of financing, lending institutions have required that the developer already have a license from FERC, a satisfactory long-term power sales agreement, a construction contract with a guaranteed maximum, and a demonstrated ability to operate the project reliably.

In the years immediately following the passage of PURPA, the general lack of experience on the part of private developers made it difficult to satisfy these requirements; at the same time, conventional lending institutions were also unfamiliar with this new form of energy development, and were themselves uncertain or reluctant about extending financing. For several years after PURPA, the climate for project-backed financing of hydroelectric projects could be described as uncharted territory, awaiting increased knowledge and sophistication on the part of both developers and lending institutions.

However, the uncertainties of project financing were somewhat mitigated by the availability of favorable tax advantages to hydro developers. Such benefits as energy tax credits, investment tax credits, and accelerated depreciation did much to create a favorable picture of project economics and enabled many developers to accurately portray their projects as financially attractive, particularly if tax benefits were combined with favorable power sales agreements and long-term, fixed rate financing. Tax benefits for hydro development played a major role in encouraging both developers and lending institutions to view hydro as sound and profitable investments.

Many of these tax benefits, however, are either being phased out or face an uncertain future. For example, energy tax credits are only available to qualifying projects which were docketed with FERC before January 1, 1986 and are on-line by December 31, 1988. Proposed tax legislation currently pending before Congress would significantly change depreciation schedules and eliminate investment tax credits. This pending legislation, known as Treasury II, comes on the heels of four major tax changes during the past five years. Therefore, developers may not be able to rely on these tax benefits in the future.

SUMMARY OF PRIVATE HYDRO DEVELOPMENTS IN THE U.S.

With these key problem areas as a backdrop, it is possible to consider private hydro development in the United States from 1978 to the present as having occurred in two distinct phases. The first phase may be termed the "gold rush" phase, when the passage of PURPA and the implementation of other government policies created the prospect of entrepreneurial opportunities in a field which had previously been dominated by utilities. Not surprisingly, these newly perceived opportunities attracted would-be developers who varied widely in terms of their knowledge, sophistication, and competence. Virtually, all were forced to come to grips with the sometimes harsh realities of successful hydro development: soundly-conceived project planning, the licensing process, power sales, and project financing, in addition to the fundamental issues of project design, construction, and operation. Nor were developers the only ones exploring uncharted territory in this first phase: federal regulators, lending institutions, and utilities all had to "feel their way" through the new and complex set of issues and considerations that arose as a result of PURPA.

This first phase took place from 1978 until approximately 1982, as borne out by the figures showing that only 76 out of the 268 projects that became operational between 1980 and 1986 went in-service during the first three years.

The second phase of private hydro development might be termed the "shakeout" phase, during which hydro developers who were unwilling or unable to come to grips with the realities of the development process gradually dropped out of the picture. The ranks of private hydro developers correspondingly became dominated by those with a clearer and more comprehensive understanding of project planning, licensing, and financing. At the same time, key institutions such as FERC, lenders, and utilities also matured in their understanding of the development process. The continuation of relatively high oil prices as well as the existence of various tax benefits combined to create a highly favorable environment for developers who were equipped to deal with the inevitable development problems.

This second phase can be said to have extended approximately from the beginning of 1983 to the present, as is evidenced by the fact that 192, or 71 percent, of the small hydro projects in service between 1980 and 1986 went on-line in the latter three years.

It is likely that private hydro development has now entered its third phase under a set of circumstances that is likely to be maintained for the foreseeable future, with the net result of limiting the prospects for future private development. On one hand, those developers that have survived the years since PURPA tend to be experienced, knowledgeable, and well-equipped to

negotiate the institutional hurdles of project development. The Key problem area of project financing has been addressed both by increasingly sophisticated developers and by lending institutions who now understand and are comfortable with structuring feasible financing packages for hydro projects.

On the other hand, however, are three highly significant factors that will tend to discourage private development in the future. First is the fact of rapidly falling oil prices as a result of increased availability of oil. This has the effect of lowering the utilities' avoided costs, both current and projected, resulting in a far less favorable power sales climate for developers.

Second is the loss of many of the tax benefits that were previously available to small hydro projects, as discussed earlier. This, combined with lower avoided costs, could have a drastic impact on the economic feasibility of many hydro projects, which in turn will affect the prospects for workable project financing.

Third is a new set of policies and procedures promulgated by FERC as well as many state agencies that will make project licensing far more difficult than it has been in the past. Strict procedures for agency consultation on environmental issues have recently been handed down by FERC and are being stringently enforced. Further, FERC has made it clear that it is not willing to issue licenses or even give approval for projects that are environmentally unacceptable --- a marked departure from previous years, during which FERC rarely explicitly denied approval despite the delays and regulatory complexities that often beset the licensing process.

These circumstances are unlikely to change unless and until the economics of energy returns to a situation comparable to that of the mid-1970's, thus creating an economic and political climate that once again is highly favorable to alternative energy development. Therefore, opportunities for private hydro development appear limited, confined primarily to projects that are economically feasible in the absence of tax benefits and despite comparatively low energy prices, and that moreover are fully acceptable environmentally.

CONCLUSIONS

From the date on projects in service presented earlier, it is clear that the passage of PURPA and other programs designed to assist and encourage hydro development did not result in sweeping or revolutionary changes in development patterns in the United States. PURPA and accompanying programs did permit non-utility developers to enter the hydro field, and they have achieved some success in terms of the numbers of new projects that have been developed. But in terms of the actual amount of new energy capacity developed since PURPA, utilities have remained dominant. This is true even when only small hydro projects (less than 25,000 kW) are considered; when large projects are included in the picture, utilities have maintained

their virtual monopoly position in hydro development, with private developers accounting for only 5 percent of new installed capacity between 1980 and 1985. Clearly, most private developers, though realizing some success primarily with very small projects, were never able to make the transition into large hydro or even to what might be termed "large small hydro" projects --- those of 5,000 kilowatts or more.

These results emerged from a set of circumstances that in general was highly favorable to non-utility development, despite the presence of problems and institutional obstacles. But these favorable circumstances have changed with falling oil prices, tougher licensing requirements, and the elimination of tax benefits. These factors combine to suggest strongly that future opportunities for private hydro development may be limited.

This is not to say that private development is dead. Although not immediately apparent based on an analysis of the available data, there are a number of small hydro projects currently under construction, or about to begin construction, which are worth mentioning. Many of these projects are in the 5 to 50 MW range and are non-utility development. For example, several paper companies and hydro development companies appear to have emerged as successful developers and have multiple projects in various stages of development. Most of these projects are anticipated to come on line before the end of 1988, when the energy tax credits are scheduled to expire. How successful these developers will be after 1988 remains to be seen. Given the right circumstances surrounding an individual project --- favorable physical characteristics, minimal environmental constraints, a satisfactory power sales and financing structure, and a developer with the experience, knowledge, patience, and resources to see the project through --- there is no reason why it cannot be brought into service successfully. But such opportunities are likely to become fewer and farther between. Meanwhile, it appears safe to assume that electric utilities will continue to dominate the hydro development scene for many years to come.

Carol H. Cunningham, P.E.

As Director of Water Resources for Morrison-Knudsen Engineers' (MKE) Eastern Region, Ms. Cunningham has 15 years of experience in civil and geotechnical engineering, and has specialized in the planning, evaluation, licensing, and financing of small hydro projects in the Eastern United States for MKE in Norwalk, Connecticut. In addition, she has experience negotiating power sales contracts, selecting financial and legal advisors, and reviewing small projects for financial institutions. Recently, she served as Task Leader for the Small Hydro Technology Transfer Project, sponsored by the U.S. Department of Energy and the Electric Power Research Institute.

FINANCING SMALL HYDRO PROJECTS

SELECTED CONSIDERATIONS IN FINANCING SMALL HYDRO MARKETS

Gordon G. Graham
Blake, Cassels & Graydon
Toronto, Ontario

I will examine various approaches to third-party financing of small hydro projects. My intent is to outline the different alternatives available.

The main lenders or investors in Canada for projects of this type include individuals, banks, credit unions, trust companies, insurance companies, pension funds, leasing companies and venture capital companies. Barriers confronting lenders include lack of information, perceived technical risks, uncertain buy-back rates and inflexible lending practices.

BANK LOANS

The typical bank loan agreement contains a series of provisions intended to ensure that the borrower will repay the loan with interest as promised. Specific covenants will limit the borrower's freedom - e.g. to make capital expenditures, undertake lease commitments, pay dividends or bonuses, borrow or incur liability, mortgage assets, etc. - while the debt remains unpaid.

Loans may be secured or unsecured. Loans might be unsecured if the lender is content to rely on the reputation and general financial strength of the borrower. If the borrower becomes bankrupt, however, the unsecured lender will recover only a pro rata share of the bankrupt's unmortgaged assets. Secured creditors are in a better position. They can at least recover their collateral or its value regardless of the amount of unsecured claims. Usually nothing is left for the unsecured creditor and most loans for small hydro projects will have to be secured by a charge on the facility and related assets.

The loan might also be secured by a charge against other fixed assets of the borrower, such as land, buildings, machinery and equipment unrelated to the hydro project.

The legal devices available to effect security arrangements include general security agreements, debentures and land mortgages.

A debenture is a promise to pay by the corporation and a mortgage or charge over a certain property of the corporation as security for the performance of that promise. The debenture may create a fixed charge on specified property and assets and/or a floating charge on the property and assets which are not subject to the fixed charge. A debenture usually changes all the assets and property of the borrower, both real and personal, tangible and intangible, present and future. A general security agreement can accomplish the same purpose except with respect to real property.

Security devices can be augmented by guarantees, whether given by individuals or by corporations. Where the project developer is the subsidiary corporation of a large parent corporation, it will be common for the lender to seek from the parent, a guarantee of the subsidiary's indebtedness. Similarly, where the shareholders of the project developer have an asset base which is substantially deeper than that of the borrower, the lender will typically seek a guarantee of the borrower's indebtedness from the shareholders.

PREFERENCE SHARE FINANCING

Loan interest is an expense to the borrowers and taxable income to the lender. There is a technique, however, for effectively shifting deductions from the borrower to the lender. The technique is the issuance of preferred shares having the characteristics of debt obligations. This is a mechanism of financing tax-exempt entities or start-up companies which do not yet have taxable income. The shares are structured so that the dividend rate is one-half of an index lending rate, for example, the prime rate, plus a small premium. The non-taxable borrower is prepared to pay this premium spread because the net cost is still less than a normal loan rate. The lender, if a corporation, receives dividends free of tax (because of the 100% inter-corporate dividend tax credit provided for in the Income Tax Act). It receives a higher return than its after-tax return on interest earned on loans.

A legislative restriction has been placed on the availability of this arrangement. The "term preferred share" provisions of section 248 of the Income Tax Act provide that if the lender has the right to require the purchase or redemption of the shares, they are deemed to be "term preferred shares" and related dividends will not qualify for dividend tax credits. That is the dividends become equivalent to taxable interest. Nevertheless, where investors can accept this type of arrangement, the financing costs to non-taxable project developers can be dramatically lowered without having legally binding assurance of repayment of the shares.

PARTICIPATION

As an inducement to the lender, the loan may be structured so that in addition to receiving regular interest, the lender

participates in project profits. This should not cause tax problems. A participating amount probably will be viewed as additional interest. If not, it will be income in the hands of the lender.

Conventional bank financing can be used for the financing of hydro projects. However, the project developer would have to devote scarce capital-raising capacity to the project. Conventional bank financing may be most appropriate for small projects where the developer has sufficient capital-raising capacity to also finance other priorities. The special attributes of special financing techniques are less important than the cost-effectiveness and administrative efficiency associated with bank borrowing, when the amount of financing required is relatively small.

RISK

The lender makes its lending decision based upon its assessment of the risk. The covenant of the borrower to repay the loan will insulate the lender from technological risk only if the loan is well secured or the financial strength of the borrower will not be affected by project failure.

It would seem that a successful small hydro project would be good collateral. From the lender's perspective, however, the project is a start-up or venture capital situation, and not "bankable" unless supported by additional collateral and a financially strong covenant. While the project may be theoretically viable, management expertise, site release, timely completion, delivery of buy-back contracts and regulatory approvals, among others, are areas of possible difficulty.

Assuming that the loan is made, there will usually be provision, in the event of default, for the financier to seize the project and operate it or sell it as an operating project.

Generally, conventional bank financing will be available only to corporations which can carry the debt obligations and pledge assets as security to lenders without reliance on the particular energy project itself.

PROJECT FINANCING

Limited-recourse financing of economically self-contained projects is called project financing. The expected cash flow from the project is the primary source of debt repayment. The loan may be supported by various technical or financial commitments from sponsors, purchasers of output, the host municipality or industry, suppliers or others, and by a charge on project assets.

In a typical project financing, the borrower may be a

corporation incorporated for the specific purpose of developing a hydroelectric power plant. A lender or syndicate of lenders will make a loan to the borrower without recourse to the general assets of the borrower. The amount of the loan facility will depend upon the guaranteed revenues to be generated from project sales. On default, the lender may assume control of the project and so will require assignments of the project site, licence and water rights and "take or pay" sale contracts.

It is possible to structure a number of variations of basic project financing including provision for additional security upon the general assets of the borrower or its affiliated corporations and/or guarantees. To the extent additional security is taken the transaction increasingly compares to conventional bank financing.

Another variation capable of being introduced is to syndicate the loan amongst a group of unrelated lenders. This technique provides additional flexibility in seeking funding and spreads the risk.

It is helpful to recognize basic credit guidelines likely to be followed by a project lender. The extent to which usual credit criteria cannot be met because of the start-up nature of the project indicates the necessity of compensating guarantees, take-or-pay contracts or the like. Even with such elements bolstering the credit, it must be recognized project finance is labour intensive from the lender's standpoint and is justified only where the profit opportunity is significant. This could mean small hydro projects would have to be pooled for project financing purposes.

Typical credit criteria include the following:

1. Avoid start-up situations <u>regardless</u> of the apparent strength of any proposed guarantors. Such transactions basically require venture capital not conventional debt financing.

2. If a deal is dependent on personal guarantees avoid it.

   Personal guarantees are historically unreliable.

3. Consider the length of time a company has been in business. Most companies in business for less than five years will probably not have the financial, marketing or management stability and consistancy to qualify as good credit risks.

4. Check to make sure that the cost of construction of the project is reasonable.

5. Look for the following in the financial statements of the project sponsor and the project feasibility study:

(a) The sponsor has a track record of sales growth and consistant profitability;

(b) Adequate operating profits (i.e., the company is profitable in its primary business activities);

(c) Ensure reasonable net profits, after tax, are going to retained earnings;

(d) Adequate cash flow proposed to cover both existing debt and the proposed lease;

(e) Positive working capital;

(f) A tangible net worth which exceeds total project investment by at least 35%. Tangible means the exclusion of such assets as goodwill, deferred costs, investments in private companies for which no financial information is available, etc.;

(g) A manageable debt load, with consideration given to the total debt and the distribution between current and long term debt."

JOINT VENTURES (INCLUDING LIMITED PARTNERSHIPS)

"Joint Venture" is a term encompassing a variety of arrangements in which individuals and corporations collectively own property and carry on a business or project. Usually the business is limited in scope and duration.

Certain elements are critical to the existence of a joint venture. The most important elements are contractual and include a contribution by the parties of money, property, effort, knowledge, skill or other assets to the common undertaking, a joint property interest in the project, a right of mutual control or management, the expectation of profit, a right to participation in profits and, usually,a limited time horizon.

Joint ventures usually take one of the following forms: a corporation in which the various joint venturers are the shareholders and are normally represented on the board of directors, a partnership (either general or limited), a co-tenancy where a real property asset is held by the joint venturers or owners as tenants-in-common or a trust in which the joint venturers are the beneficiaries. As a general matter and absent income tax considerations, most joint ventures are established as corporations. Partnerships, co-tenancies and trusts are used as joint venture vehicles primarily for tax reasons. Joint ventures have become an attractive method of raising capital because equity can easily be given to the lender in return for repayment which are less rigidly structured than in most other financing arrangements.

The key distinction is between joint ventures which are partnerships and those which are not. The reason for distinguishing between joint ventures and partnerships is tax treatment. A partnership must claim its expenses at the partnership level. Joint venturers on the other hand are entitled to claim their pro rata share of expenses individually. Where it is important for tax purposes to qualify as a true joint venture, an advance ruling should be obtained from Revenue Canada.

JOINT VENTURES

In determining whether or not a joint venture is a partnership in Ontario, reference must be made to the Partnerships Act. The Act defines a partnership as "the relation that subsists between persons carrying on business in common with a view to profit". The key feature of a partnership is that it must carry on a business. Common ownership or common sharing of profits or losses are indications of partnership but are not, of themselves, conclusive.

The simplest form of joint venture is one in which there are only two parties, the project developer and the lender. Each would have a percentage interest in the joint venture, which is for tax and other reasons not to be a partnership. The two parties would enter into a co-tenancy agreement whereby each would hold an undivided interest in the same property but would earn income independently of each other. It should be noted, however, that common servicing and management activity by co-owners would suggest that the operation was a common business activity rather than merely an investment in property.

The financing for the joint venture would be provided by each joint venturer in its individual capacity in proportion to its share in the joint venture. The respective shares of the parties in the project would give rise to a question of control. The project developer will feel it has more know-how and so should make important decisions unilaterally and expeditiously. The lender, on the other hand, will perceive it has the financial risk and must control important decisions. The question of control can be resolved by a requirement that consultation on financial or other major decisions be conducted expediently.

Although a joint venture which constitutes a business (i.e. a partnership) is not technically a legal entity, it will be treated as such for tax purposes. The accounts of the joint venture will be consolidated and claims for CCA taken at the joint venture level. The principal significance of this tiering of benefits is that the venturers must agree on the amount of CCA to be taken by the combined operation on the basis of their own particular tax positions. The benefit of flexibility in electing whether to claim CCA is lost.

As a practical matter, there is little difference from a tax standpoint between a joint venture partnership and corporate forms of organization except that the aggregate profits and losses of the joint venture for the year are automatically and of necessity transferred through to the venturers in proportion to their agreed interests in the venture and it is not possible to retain joint venture profits for later distribution.

As a joint venture normally entails large start-up costs, including legal and other expenses, it is a financing technique not particularly appropriate for small energy projects. It can be an important and appropriate method for financing large projects or pooling a number of smaller projects however, usually in combination with other financing techniques.

A key concern with respect to the viability of joint venture financing is whether or not it expands a project developer's access to capital. Joint ventures involve contribution by the respective joint venturers of an amount they are willing to place at risk. The contribution of the project developer will not adversely affect its capital-raising ability except to the extent it finances the initial contribution to the joint venture itself.

Although risks involved in a joint venture are often borne by the joint venturers in proportion to their participations, the joint venture agreement can be drafted in such a way as to shift the allocation of risk to the project developer or to other specific parties.

LIMITED PARTNERSHIPS

If the joint venture constitutes a relationship between two or more taxpayers carrying on business with a view to profit, it may be regarded as a partnership for tax purposes. Interpretation Bulletin IT-90 is designed to assist taxpayers in determining whether or not a particular arrangement constitutes a partnership from the point of view of the revenue authorities.

A limited partnership is like an ordinary partnership except that the partners are of two types. On one hand are the general partners who operate the business of the partnership and have unlimited liability and on the other hand are the limited partners, who must not control the business and are insulated from all liabilities of the partnership in excess of the capital they agree to contribute. The limited liability status of limited partners depends upon their actual conduct, as well as on the formal agreement and statutory registration.

The limited partnership approach to financing has been adopted where the proposed business activity will generate significant tax write-offs, such as the oil and gas industry, farming, mining, research and development, films, etc. Limited

partnerships should be considered in small hydro projects to enhance the value of Class 34 CCA.

A limited partnership is managed by a general partner. The general partner is usually a corporation incorporated and controlled by the project sponsor. The limited partnership agreement will provide that the general partner is entitled to recover only its expenses (e.g. overhead, professional, technical and administrative fees and the cost of establishing the limited partnership). Following the payment of such expenses, the profits and losses of the partnership are to be shared by the limited partners in accordance with their capital contributions, or, on an agreed formula.

The essential attraction of investment in a limited partnership is the tax treatment afforded the partnership. Partnerships, unlike corporations, are not taxed as separate legal entities. The profits and losses of partnerships are determined at the partnership level and each partner includes in his personal income his portion of the partnership profit or loss.

The disadvantages of the limited partnership vehicle include the limited partners' lack of control over the affairs of the partnership and the absence of statutory standards of voting, information disclosure and control.

The tax treatment of limited partnerships is very similar to that of general partnerships in that the profits or losses of the partnership are divided among the limited partners in accordance with the partnership agreement. Any beneficial write-offs generated during the early stages of the project from CCA or other deductions (at the partnership level) are shared by the limited partners through their participation in the "losses" generated by these deductions. The deductability of losses by limited partners, however, is limited to the amount they have invested.

Under the Income Tax Act, the profits and losses of the partnership for the year will be attributed to the partners at the end of the taxation year regardless of the cash distributions to the partners during the year. Distributions of cash cause a reduction in the adjusted cost base of the recipient partner's partnership interest as do partners' shares of any losses, whereas the attribution of profits from the partnership causes an off-setting addition in the adjusted cost base of the partnership interest. If a partner sells his partnership interest in the middle of a fiscal period, however, there is no provision for adjusting the attribution of profits and losses for tax purposes or for making an adjustment to the adjusted cost base. These matters have to be worked out between the selling and the purchasing partners by contract.

LEASING

A lease is simply a contractual arrangement whereby the lessor permits the lessee to use tangible property for a specified time in exchange for rent. The rent payments are usually unconditional obligations, although contingent rents based on hydroelectric production could be used.

The cost of leasing tends to be marginally higher than the cost of borrowing. However, gross rents are tax deductible by the lessee.

The term of a lease depends upon a number of factors. The most important is the expected useful life of the leased equipment. The time required for amortization of the lessor's capital cost, the maturity of the lessor's funding and tax considerations are also relevant.

Validity of a lease for tax purposes (it must not be in substance a sale) will affect the distribution of CCA deductions and any investment tax credits between the lessee and lessor and the tax treatment of the lessee's payments.

In a true lease, the lessor retains ownership of the leased equipment for tax purposes. The lessee pays rent during the lease term. At expiry of the term, the lessee usually may renew the lease for an extended term or buy the equipment for a specified option price. The lessor will claim CCA deductions and the lessee will expense rental payments.

A finance lease (see IT 233R, not CICA Guideline 3065) or tax-invalid lease is the equivalent of an installment purchase contract. The lease payments repay the full cost of the equipment plus an inherent interest factor. At the end of the term, the lessee may be entitled to purchase the equipment for a nominal amount. For tax purposes, the lessee is regarded as the owner of the equipment and is entitled to claim CCA deductions. Depending upon the respective tax positions of lessor and lessee, it is prudent to structure the leasing transaction in the most tax-effective manner, so that the party capable of benefiting most from the tax benefits will be able to claim them. A problem with small hydro project leasing will be the conflict between the high retained value of the project after a ten year lease and the lessor' requirement that the lease be a "full payout lease" - i.e. one in which the lessor will have fully recovered its investment, costs and required return, upon receipt of the last payment. Practically speaking, the last payment is the option amount. If the economic life of the project is forty years, a mortgage amortization of the capital cost over ten years will mean the "balloon payment" - i.e. the option amount - payable at lease expiry, will be much less than the presently projected project value as at such future date in result the lease option may be viewed as a bargain option for tax purposes and may invalidate the lease, and disturb the intended allocation of tax benefits.

SMALL BUSINESS DEVELOPMENT CORPORATIONS

The Small Business Development Corporations Act requires that a small business be engaged in a prescribed activity if it is to be considered a suitable target for S.B.D.C. investment. The legislation prescribes four activities including manufacturing and processing.

The requirement is that the corporation must produce, or put into marketable form, goods or materials for sale or lease from raw unfinished or prepared goods or materials and must do this by changing the form or content of those goods or materials. An argument can be made that small hydro projects may fall within the scope of the Small Business Development Programme. Accordingly, this presents a further financing alternative, taking advantage of the Ontario 30% grant to effectively reduce project costs.

CONCLUSION

The appropriate financing technique is a function of many complex factors including the creditworthiness and tax capacity of the project sponsor, applicable barriers to financing and investment objective. When these are determined the range of willing lenders should be considered. The particular capabilities and lending or investment attitudes of the lenders should be carefully examined, as well as the scale and risk associated with the project. Only then should the investment or lending technique be selected. The object of selection should be to maximize the bargaining power of the project sponsor in attracting investors, achieving true non-recourse financing and obtaining favourable loan terms.

Gordon B. Graham is a Partner in the firm Blake, Cassels & Graydon. Mr. Graham specializes in commercial and banking law, and acts for lendors and investors who are interested in small hydro developments or other commercial ventures.

FINANCING SMALL HYDRO DEVELOPMENTS

John E. Lackey
Commerce Leasing Limited
Toronto, Ontario

Money - it's sort of a magic word, it captures our attention and is something that I dare say every person in this room thinks about at least once a day. Some smiling at the thoughts while others frown, one thing is certain there doesn't seem to be a middle ground. For the next few minutes we are going to talk about money, not necessarily how it applies to you personally but how it would apply to and affect a small hydro project which is the reason for our being here in the first place.

In place of the word money we will substitute financing, and as I am sure you will realize financing a small hydro project is certainly one of the major decisions that must be made and in most cases it is absolutely crucial that the proper method of financing be arrived at so the project being undertaken is given the best possible chance for success. This decision in itself is a real challenge to you as the decision makers and it needs to receive the attention and effort it deserves to make sure you examine all the alternatives available.

Now in the past, undertakings in the energy field have been handled along fairly historical lines where government loans or outright grants were taken into consideration or the necessary debentures issued and eventually turned into a bank or trust company loan or line of credit and in this latter case, although an outright guarantee by a government source may not be forthcoming, if the transaction was in the Province of Ontario, the credit requirements would probably, at least, call for a written opinion from the Ontario Municipal Board supporting the entire undertaking and the proposed financing plan. Now, having said that, the various approaches obviously work, although on occasion can be rather frustrating. We are, however, now entering a new era in the development of energy not only in small hydro projects but in almost any other energy-producing situation you can name.

An examination of the overall energy industry would indicate that some different thinking and planning insofar as financing

is concerned is called for as governments at various levels change their past standard policies as to outright grants and assistance of almost any type to either private industry or municipalities in an attempt to, if not balance their budgets, at least bring them down to the point where, when you read the final deficit figure it is some amount you can vaguely understand. The point I am attempting to make is that from this point on, the financing of small hydro undertakings is going to change dramatically. I believe this is good for the industry as a whole as it will give you a far wider range of financial vehicles to choose from, provided you take the time and trouble to check them out thoroughly and find the best financial method that would suit your future plans.

To conduct this search, you need, of course, to fully understand your own position and what you basically wish to accomplish in undertaking the project in the first place. You then need to examine in detail the various financial plans available and decide which ones can be discarded immediately as being unsuitable for reasons dictated by the project itself, the repayment term required, lack of flexibility; from here the list can go on to cover probably four or five other qualifications. The various types of financing plans you will be examining would probably cover the following:

debenture financing
bond issue
venture capital
joint venture
leasing
conditional sale contract
bank loan
line of credit
limited partnership

As this presentation is being put together, there is apparently some anticipated change in the way limited partnerships can be handled which will take affect with the upcoming Federal Budget. Apparently, this will affect the tax benefits available under this type of handling. As a sidelight, it also appears the same thing is happening in the United States where limited partnership financial dealings have been very popular in the energy industry over the past few years.

Once you have selected the two or three methods of financing that survive your scrutiny and list of requirements, we believe the only safe method of progressing from this point is to ask representative companies from each type of financing you feel is appropriate to submit proposals to you in writing as to what can be done to best meet all the needs of the upcoming project. When you request these proposals, it is helpful if you tell each participating company what other financing fields you are checking so when they do reply to your inquiry they will either point out in the proposal or discuss verbally why

their particular type of financing plan is more appropriate to your needs.

One of the most important points is that you do not simply choose a method of financing simply because it is offered at 1/8 or 1/4 of 1% less than any of the other proposals. Of prime importance to you should be how well the financing plan fits the actual requirements of your project. It is at this point you need to carefully study such things as flexibility in both basic rate structure and term. Whether the rate involved is based on floating rate or fixed and whichever one of these it is using is that appropriate to what you consider to be happening in the money market today and during the term of the financial transaction. You also need to examine any additional covenants required over and above the basic documentation and how these covenants may affect your position or borrowing powers in the future. If it comes down to a very close call, you might also consider what type of expense is involved in actually entering into the transaction and this would include legal costs, documentation, your administrative costs, etc.

This is a very short checklist presented for your consideration and it is by no means complete, but if you consider doing this on your project, it will at least give you some food for thought as to some of the approaches you should use to get the most for your dollar cost.

Having said all this, I would now like to say that I hope the final short list you decide to investigate closely will include leasing as one of the methods of financing. This preference on my part for leasing may be adequately explained by the fact that I make my living in the leasing field and I presume that is enough said about that.

Before getting to the actual details of a lease, let's talk for a minute about credit and how it enters into the picture. When hydro projects are undertaken by individuals, partnerships or firms in the private sector, normal financial credit policies will apply. The individuals principally concerned with such an undertaking are, no doubt, aware of such policies and also of whether they or their companies are capable of attracting a favourable credit decision on the number of dollars involved. In dealing with credit insofar as municipalities are concerned, somewhat different criteria are used and in most large financial institutions in the Province of Ontario, in addition to such things as engineering feasibility studies, project cash flow statements and similar documents, will look for a letter from the Ontario Municipal Board or its equivalent in other provinces, that in effect says the Board is in agreement with this undertaking in the manner outlined to it by the municipality. In this presentation to the Municipal Board, the financial institution will normally request that their legal representative be permitted to accompany your lawyer during the presentation. In the results of any credit assessment, you

will find the assessment of individuals or companies from the private sector to be more restrictive than those imposed on municipalities. The reasons for this are obvious, however, in addition to these I would ask you to remember that the financing of energy projects is rather new to financial institutions and until it becomes a more normal line of their business, there will be a trend to be very cautious. This is particularly true in the case of entrepreneural individuals who wish to make a start in this business, either on their own or in conjunction with a partner. If you would permit me, a word of advice to such individuals. That word would be 'caution'. You should not proceed with any part of the undertaking until you are in possession of a written commitment from a financial source to supply the necessary funds to complete the project through the testing period and until it is ready to actually go on line plus a realistic repayment term of all dollars involved.

Following credit approval, the leasing company will issue a lease proposal outlining the various terms and conditions on which it wishes to proceed. This is where negotiation enters the scene and it will be between the lessee and the lessor on these various conditions. The approval will include the lease term in years, the formula for arriving at the dollar amount of each lease payment, when these payments will be made, insurance, maintenance of equipment, and at what point in time and at what cost the project can be purchased by the lessee.

Of these points, I suppose the most concern is with the actual lease payment. The proposal will quote a dollar amount of payment as well as a lease factor used to arrive at the dollar figure. The leasing company in arriving at these figures bases its quote on a position from a financial index. This index can be Prime Rate, Bankers Acceptance or, as in the case of my company, Certificates of Deposit. When I say take a position from one of these indexes I mean the leasing company will base its bid on, for example, Certificates of Deposit rates for five years of 10.75% and to this a spread of 75 points will be added. This is the position of the leasing company. The result, therefore, will be a Certificate of Deposit rate of 10.75% + .75 for a total of 11.50%. This position, which is 75 points over the quoted index, will be maintained until the actual lease term commences. If, at the time of commencement of the lease, the Certificate of Deposit rate has dropped to 10%, then the overall rate content in the lease will be 10.75%. If, on the other hand, the CD rate has increased to 11%, then the interest content in the lease will be 11.75%. In other words, the spread of the 75 points remains constant while it is possible that the basic index rate may change. The important point here is that the interest content is guaranteed to remain the same for five years of the lease no matter what happens to money market rates during that time. This is referred to as a fixed rate over a fixed term. The lease payments do not change - they are fixed for the full five years.

Let me digress here for a moment for a word of explanation. You'll notice I have been using the word interest as it relates to leasing. In actual fact when describing a lease, this word 'interest' should not be used, as technically, a lease does not contain interest but simply lays out either a factor or the actual lease or rental payment in dollars that is required. I have no intention of insulting your intelligence by telling you that any financial institution in Canada would undertake a project 'without' some form of return to itself that would have an effect on its bottom line and, therefore, we may as well call this mystical amount 'interest' as to refer to it in any other way.

The second point of concern in the proposal is the purchase option which is usually quoted as a percentage of the total original dollar investment the leasing company has in the project. If the original investment by the leasing company was $1,000,000 and it is thought at the outset the project will be worth 30% of this amount at the end of the five-year term, the lessee can become the owner of the project for $300,000 at the end of the 60th month or five years.

The purchase option need only meet the requirement that it represents what can reasonably be expected as its worth, based on today's costs, at a point in the future. In our case, five years in the future. Even though during that five years the world may have gone through its historical upward trending tendencies, this option figure will hold true and cannot be changed.

Let me run through a few of the points that leasing concerns itself with and you will see where some of the differences occur between this method of financing and that of straight financing by a loan or bond or whatever other method is used. I guess the largest and foremost difference is that in leasing the leasing company, who is known as the lessor, actually owns all the equipment connected with the hydro project with the exception of the land. In the majority of cases, the land on which the project rests is not readily available for any type of supporting land mortgage or similar debt instrument. It is, however, necessary that some form of protective relationship be in existence between the actual equipment asset and the land, and this is normally overcome by taking a form of agreement from the government agency involved that the hydro project stands on their land or dam or whatever but with their permission and full recognition of the leasing company's ownership of the equipment.

The selection of the type and manufacture of all equipment is the prerogative of the lessee. After receiving the written commitment on the part of the leasing company to handle the transaction, the lessee is then appointed to act as the leasing company's agent and place orders for the equipment directly with the manufacturer or selling agent. Any guarantees or

warranties which accompany the equipment are passed directly through to the lessee.

Under a leasing arrangement, there is no investment required until the project is completed and in a working condition and ready to begin production. During the construction phase, as dollars are required to pay off the completion of small contracts or to pay for equipment, invoices issued by the supplier or contractor are made out to the leasing company but delivered to the lessee who, in turn, holds the invoices until, in their opinion, they should be paid. This system continues through until the project is in a completed form. The lessee, or end user, is the one who triggers payment and by doing so indicates to all concerned that he is satisfied with that portion of completed work or piece of equipment.

Any holdbacks have been agreed to long before this point, usually when the contract for the project work was first given and these holdbacks are, of course, held until the lessee indicates to the leasing company that they should be paid. The important point here is that the lessee only begins to pay interest on the day that funds are issued. The interest on issued funds is usually charged on a per diem basis and accumulates on the outstanding dollars until the project is completed and all parties are then ready to enter the formal lease agreement. The total interest accumulated up to the day the lease begins can either be paid in full at that point or it can be capitalized into the lease as part of the leasing company's investment in the transaction. You can, of course, pay this interest off as it accumulates month by month during the construction period, however, the ability to capitalize it into the lease is there for your convenience if this would make your bookkeeping easier.

Now let's suppose we have on our hands a finished hydro project ready to go into operation and to begin earning its keep. The formal lease agreement is signed and it bears a term usually dictated by the projected cash flow statements so that the complete undertaking pays for itself as it goes along with as little disruption to the current cash flow situation prior to the project being undertaken. Now, assume a term of five years has been agreed to by all parties. It represents a reasonable term for the lease to run and, as stated before, the beginning of the lease coincides exactly with the plant being in a position to begin earning dollars. The lease payments by this time, of course, have been arranged well in advance and they are payable either monthly, quarterly, semi-annually or annually, and the point to remember here either in arrears or in advance, and the point to remember here is that if you have payments in advance, the interest dollar content in the lease will be less than if payments are made in arrears.

At the end of the five-year term when the lease has been completed, you are given the opportunity to exercise a purchase

option in the dollar amount that was originally quoted to you prior to the lease being entered into. This amount of money which is usually expressed as a percentage of the total original cost of the undertaking can then be paid by you in one lump sum and by doing so, ownership of the hydro plant is turned over to you by way of a Bill of Sale. This option to purchase is exactly that - it's an option - however, should you choose not to exercise the option, you would then enter into an additional specific term which, in leasing parlance, is known as the stretch term. For the sake of our example, let us say that the stretch term is an additional 13 months and then at the expiration of this time you will have made your lease payments for a total of six years and one month. It is at this point the leasing company becomes financially indifferent as they have received all of their original investment back plus whatever charges occurred for the use of the money.

The important point to remember here is that if you choose to buy the plant at this point, six years and one month after start-up, then you are required to pay the 'fair market value' represented by the plant itself. As you know, in these days of fluctuating values this could be either a good thing for you or a very bad one. The fair market value of the plant is arrived at by having an evaluation done by a recognized authority that is acceptable to both the lessee and the lessor and whatever figure he comes up with is the one that you must pay at this point if you wish to be the owner. Perhaps you will choose not to be the owner and to continue to lease the plant. If this is the case, you will find your leasing payments drop drastically because, as I said before, the leasing company is then financially indifferent and any money you pay from this point on is simply additional profit earned on the transaction. I am sure you are no more anxious to make some leasing company rich or richer than they were at the end of the firm lease period, therefore, it would appear the best action to follow is to exercise the purchase option when it is offered.

Let me sum up just some of the benefits of leasing which include:

1) No initial investment is required;

2) Dollars in use, and therefore subject to interest, are not required until the very day the project demands;

3) The leasing company does the bookkeeping for you until the project is completed;

4) There are no up front fees of any kind to be paid;

5) Payments on the lease can be regulated to either monthly, quarterly, semi-annual or annual, and may even include irregular or actual skip payments during certain seasons if required.

As a financing method, leasing is certainly not presented to you as the perfect way to handle every project. In fact, in come cases, leasing would be the incorrect vehicle for you to use. However, this alternative method of financing is the right method to use in a sufficient number of cases that it does deserve your close examination before you make a final decision on which financing method to follow.

John E. Lackey is Vice-President of Commerce Leasing Limited, a subsidiary of the Canadian Imperial Bank of Commerce. Prior to joining Commerce Leasing, Mr. Lackey had previous experience with Midland Marine Bank, Manufacturers Hanover Bank, Conneticut Bank and Trust, Royal Bank of Canada, and the Canadian Imperial Bank of Commerce.